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CPUC GHG MODELING
STAGE 1
DOCUMENTATION

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1. Overview – Stage 1 CPUC GHG Modeling – October 31, 2007

This document provides an overview to the CPUC GHG Model Stage 1 activities and documentation. The overview includes the project goals, process, methodology, and high level results. This document also provides a 'roadmap' to the supporting documentation in the overall effort.

Project Goals

Stage 1 (Now to End of November)

The CPUC GHG Modeling project is divided into two stages. In Stage 1, the analysis focuses on the costs of reducing green-house gases in the electricity and natural gas sectors. This is a cost-based analysis that provides cost and supply estimates for different clean energy resources available to California and the rest of the WECC (including renewable energy, energy efficiency, and low-carbon conventional technologies). The state's electric and natural gas load-serving entities (LSEs) are modeled explicitly in the analysis in preparation for Stage 2, but the focus in Stage 1 is on sector-wide results. The goal of Stage 1 is to inform the CPUC record of the costs of meeting a sector cap set at different levels of CO2e for input into the CARB scoping plan, beginning with the integration workshop scheduled for March 2008.

The initial results of Stage 1 are based on meeting 1990 emissions levels for the two sectors in 2020. This level is the proportional sector responsibility for emissions based on ARB estimates for 1990 emissions levels and reflects a reduction of approximately 25% in emissions from 2008 levels in the electricity sector. Additional scenarios will likely be evaluated to inform the CARB scoping plan.

Stage 2 (December – August 2008)

In Stage 2, the analysis will focus on modeling policy options to implement AB32 in the electricity and natural gas sectors including entity-specific allocations and flexibility mechanisms including emissions trading. To evaluate the impact on California's LSEs, the model developed in Stage 1 will revisit the assignment of emissions to LSEs and other LSE-specific assumptions. The goal of Stage 2 is to identify lower-cost and/or easier to implement approaches to meet the AB32 goal in the electricity and natural gas sectors.

Process

The project is managed under the CPUC GHG proceeding R. 06-04-009. Like other CPUC proceedings, the process is designed around an open process to identify areas of agreement and disagreement among stakeholders, and provide ample opportunity for comments by all parties.

To facilitate this process, the research team led by Energy and Environmental Economics, Inc. will provide the GHG proceeding with the modeling results, documentation of all input assumptions, and an analysis tool so that parties can evaluate the 'robustness' of the results. In Stage 1, the range of potential results will help inform the CARB scoping plan of what is possible and at what cost in the electricity and natural gas sectors.

Throughout the project, numerous input assumptions and methodology choices have been made. The input data has explicitly been limited to publicly available information so that all of the data sources can be provided to all parties on a transparent basis. Methodology choices have been made based on the project team's judgment and available time and budget. Comments by parties on both the input data and methodology choices are intended to be part of the process.

The analysis tool used by the project team is being made available to parties so that they can evaluate the sensitivity of the results across a range of input assumptions. The intent is that a party to the proceeding can change an assumption, document its source and rationale, and provide their analysis results in comments. More specific guidelines on comments will be provided at the November 14, 2007 workshop.

Modeling Overview

Electricity Sector GHG Model

In Stage 1 the project team has developed cost-based, bottom-up estimates of the cost of meeting 1990-level emissions in the electricity and natural gas sectors. The 'cost-based' aspect means that we have estimated the revenue requirement of new utility investments, and the required price for merchant generators to meet a return on equity requirement, for each resource addition. Theoretically, this is the same cost as a perfectly efficient 'market-based' approach to procure each resource. The 'bottom-up' aspect means that we have evaluated individual resources of different types that will be required to meet 2020 load and energy levels, and then summed their individual costs to estimate the total cost of reaching 1990 emission levels. This is not a macro-economic or econometric model of the sector.

The Stage 1 cost analysis is developed in several steps. In the first step, the project team develops a single 2008 case that includes the current loads, energy, and generation resources. The intent of the 2008 case is to present a starting point that reflects current conditions, and provides the ability to benchmark the model to other estimates of the State's current emission levels to verify that the model approach is working.

In the second step, the project team develops two alternative reference cases for 2020. Each reference case begins with the current 2008 case, but adds different resources to meet 2020 forecasted load levels depending upon policy assumptions. In the first 'business as usual' case, resources are added based on an assumption that current levels of energy efficiency persist and a 20% RPS standard is reached through 2020. In the second 'aggressive policy' case, resources are added to satisfy goals that are increased from current goals such as a 33% RPS and high goals for energy efficiency saving in 2020. Neither reference case results, by itself, in a large enough reduction in emissions to reach 1990 emission levels.

In the third step, the project team develops two 'target' cases that reach the 1990 emissions level target. The guiding principle for the two 'target' cases E3 developed from the reference cases is to develop resources in order of cost. There are many possible ways of meeting a given target level of emissions and the analysis tool is provided to parties to test alternative approaches.

With the base case and the target case completes, cost and rate changes, and costs of CO2 reduction, are evaluated as differences from 2008, and between the reference cases and target cases in 2020. For example, costs of the target case in excess of the reference case provide an estimate of the costs of meeting the 1990 emissions target in 2020. The estimated rate increases between 2008 and the 2020 reference cases provide an estimate of the impact in the absence of a sector target. A number of metrics are evaluated based on these differences for rates, total customer cost, and cost per ton of CO2e reduced.

Natural Gas Sector GHG Model

The natural gas sector model uses the same basic methodology, but is significantly less complex than the electricity sector model since the amount of carbon per unit of consumption is constant for natural gas. In addition, there are relatively few 'resource options' for natural gas. Therefore, there is only a single reference case for 2020 based on the forecast for natural gas sales. Similarly, the project team evaluated only energy efficiency as a potential reduction strategy for achieving the natural gas emissions target.

Signal vs. Noise

In any long-range forecast designed to guide policy choices, it is important to isolate the key drivers of results from the myriad issues that may be important in some contexts, but can distract from the task at hand. Therefore, the project team has tried to focus most of its analysis on issues that it considers 'key drivers' that are important to overall results. Since the analysis in Stage 1 will inform the CPUC Interim Decision leading to the CARB scoping plan and integration workshop, we want to provide an analysis structure that is robust across a reasonable range of the key drivers so that the record includes likely ranges of costs in the electricity and natural gas sectors.

The following table provides the key drivers that the project team has identified in Stage 1, and the 'default' assumptions for each of these key drivers that are used in the reference cases and target cases. The project team plans to verify the robustness of the results for these key drivers through sensitivity analysis and alternative target cases to the extent that time is available.

Table 1: Key Drivers and Working Assumptions

Key Driver - Signal	**Working Assumption / Approach**
Resource Costs (both conventional and renewable generation)	Cost estimates try to capture recent cost increases in generation
Federal Tax Treatment (PTC, ITC)	Assuming tax incentives are continued through 2020, except those limited to a specific quantity of new generation
Market Transformation Effects	Included as a sensitivity analysis
Natural Gas Price (and other fuel prices)	SSG-WI forecast for all fuels is scaled so that CA natural gas matches MPR forecast
Load Forecast	CEC 2008-2018 Forecast, adjusted for energy efficiency achievements
Long-Line Transmission from California to distant renewable resources (e.g. WY, BC, MT, NM)	These options are evaluated as a sensitivity only.
Energy Efficiency	Reductions are calculated as a % of economic potential.
Generation Additions from 2008	TEPPC additions based on utility long term plans plus regional load / resource balance to meet 2020 load and energy
Generation Subtractions from 2017	With RPS additions some conventional plants removed and not needed (e.g. new AZ coal)
Generation Retirements / Retrofit / Repowering	Using TEPPC assumptions, which is essentially no retirements of existing plants.
Emission intensity of unspecified imports	CPUC methodology for unspecified imports (1100lbs / MWh)
New nuclear power plants	Included as a sensitivity analysis

Tool-based approach

The GHG modeling analysis uses two tools in combination for analysis. The spreadsheet-based GHG Calculator is used by the project team and provided to parties to evaluate alternative resource plans that can meet target emissions levels. This simplified tool is useful because changes to inputs can be accommodated easily and analysis results can be updated. In addition, all of the calculations are transparent to all stakeholders because all of the formulas are provided in the spreadsheet tool itself.

The second tool used by the project team is the production simulation model PLEXOS. This tool contains a detailed nodal model of the entire WECC including individual generators, transmission lines, loads, and fuel prices. The PLEXOS model dispatches the system at least cost, subject to constraints such as transmission limits using an optimization algorithm, and reports the resulting marginal cost of the highest cost resource dispatched, and emissions intensity for each plant by hour for each year evaluated. The PLEXOS dispatch is used to estimate 'cost-based' market prices in the WECC which are an input to LSE cost, emissions levels which are used to verify targets are met, and feasibility of the overall dispatch which is used to verify that sufficient resources exist on the system for reliable operation.

The GHG Calculator is designed so that the project team and stakeholders can run many cases easily, and PLEXOS is used to verify that the resource plan is still feasible. In order for the GHG Calculator to be able to evaluate many target cases, it is designed to 'extrapolate' from a feasible PLEXOS solution over a range of input assumptions. To check the feasibility of the extrapolation, the project team will test variations of as many of the key drivers listed above, and their impact on emissions, as is possible in the available time.

'Roadmap' to the Supporting Documentation

The following set of documents has been developed to describe the methodology, document the input assumptions, and provide initial results of the analysis. The initial release of documents focuses on input data, which is being released at the earliest possible time to provide parties the most time for review. Results will be released on November 7, 2007 along with a few other supporting materials as indicated in the following list.

The documents are organized into five 'sections': modeling methodology, inputs, reference case and target case results, model benchmarking, and the GHG calculator. The individual document format will allow parties to download and comment on the specific input or data that they would like to comment on without the whole analysis. For convenience, all of the documents have been compiled into a single pdf document, and a single compressed folder.

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2. Methodology for Developing the 2020 Reference Cases

In Stage 1 modeling, we developed two 'reference cases'. The first 'Business As Usual' reference case reflects an extension of existing energy efficiency levels and a 20% RPS level from now through 2020. The second 'Aggressive Policy' reference case reflects 33% RPS and a number of other increases in achievements such as energy efficiency. Together the reference cases represent bounds on the likely level of energy efficiency and renewables under the existing, pre-AB32 policy framework. The specific policy assumptions underlying each case are documented in the policy assumptions short section.

The methodology for developing the 2020 reference cases influences the overall results of the project. Therefore, we strive to be as clear as possible on the approach for building the reference cases so that parties can comment on the approach and assumptions along the way.

Once the reference cases are established, the GHG Calculator can be used to change the assumptions on resource mix, implementation levels of targeted policies, and other sensitivities from 2008 through 2020. The 2008 initial year in the GHG Calculator is primarily to serve as a benchmarking tool, and to confirm the reliability of data sources used, including LSE-specific ownership and contracts (see respective sections). It is also used to benchmark the methodology for the assignment of emissions (see benchmarking section).

The 2020 results of the GHG Calculator will be measured as the differences between each reference case and the targeted case that reaches target level of emissions in 2020. For example, the 'Business As Usual' reference case may result in emissions X MMT CO2e above the emissions target. The target emissions level is achieved in the target case primarily through greater development of low-carbon energy resources and increased energy efficiency. This reduction of X MMT CO2e results in an annual sector cost increase of $Y per year. The sector cost of achieving the target, on top of the costs incurred in the 'Business As Usual' reference case is $X/Y per ton CO2e.

Approach for Developing 2020 Reference Cases

1. Start with WECC Transmission Expansion Planning Policy Committee (TEPPC) database (beta version released Oct. 1st, 2007)

The beta version of the TEPPC database contains a complete 2017 WECC case including peak demand, energy requirements, power plants, transmission plant, and fuel prices. The project team expects this database to become the standard for electric system modeling in the west.

Since it is a beta version, we expect that problems will be identified and corrected as researchers (such as the project team) begin to work with the database. Initial comments were due on Oct. 22nd, and continued improvements and versions will likely be developed in the future. However, working with the latest data, which is designed in part to correct problems in the precursor SSG-WI will provide the best available data to begin the modeling.

2. Estimate 2020 loads for each reference case

Although the TEPPC database contains 2017 load levels (including both energy and demand) for each zone throughout the west, we replace the TEPPC loads with our own estimates. This is necessary to (a) ensure that the model is based on the best, most recent load growth information, a key driver in the overall GHG footprint of the state, (b) document the source of the load growth forecast, and (c) enable the model to modify the load growth forecast for distributed energy resources that are behind the meter. The load cases are built up from the 2008 initial year case by (a) applying region-specific growth rates, and (b) for California, subtracting out additional "behind-the-meter" distributed energy resources as described below. Load growth assumptions are specified in the load growth section. A comparison of projected load and energy from our 2008 initial year levels for the reference case, TEPPC forecast, and CEC Scenarios Projects is also provided in the benchmarking section.

The California load growth cases are based on the updated CEC load forecast by LSE from 2008-2018. For the Existing Policy case, the projections include levels of energy efficiency and distributed resources that are consistent with existing state policy and funding levels. The Aggressive Policy case includes more aggressive energy efficiency. Reference case forecasts for the Existing Policy and Aggressive Policy scenarios are described in energy efficiency section. The load forecast is further reduced by a forecast of photovoltaic penetration, and demand response. Assumptions on each resource type are documented in their respective sections. Our 2020 reference cases and target cases assume that demand response will meet the EAP II goal of 5% of California's peak demand (including both IOU and POUs). California load in 2020 is expected to be approximately 72,000 MW and DR is expected to be approximately 3,600MW. Both of the reference cases assume the same level of penetration of these distributed resources.

For the other regions in the WECC, we use a single load forecast for both reference cases developed from a survey of load growth forecasts in major western utility resource plans.

3. Adjust WECC generation to ensure RPS compliance and 2020 load-resource balance for each region

With the exceptions of Wyoming, Idaho and Utah, all western states have renewables portfolio standard (RPS) laws that require utilities to serve a portion of their retail load with qualifying renewable energy resources. We estimate the 2020 renewable energy requirements based on a load-weighted average of the state RPS requirements in each of our ten WECC regions. In some regions, the TEPPC database does not contain sufficient renewable resources for the region to be in compliance with their RPS requirements. For these regions, we add renewable energy resources based on the E3 renewable energy supply curves for each region. In order to do this, we must first adjust the E3 supply curves to account for all the renewable resources in the TEPPC database. We do this by assuming that the TEPPC resources represent the lowest-cost resources in the E3 supply curves in each region. All renewable resources that we add are assumed to be located within the region; therefore, no out of state transmission projects for renewables are assumed in the reference cases beyond what is already included in the TEPPC database. The resource potential for each type of renewable generation is documented in a separate sections: wind, biomass, geothermal, central station solar, and small hydro.

Once the renewables are added, we adjust the conventional energy resource stack by adding or subtracting resources to ensure that each region is in load-resource balance in 2020, including planning reserve margins. Conventional resources are removed when the additional renewables for RPS compliance in each zone are greater than the growth between the 2017 and 2020. When removing resources, we start with 2020 and work backwards, removing the last resources added. This process ensures that each WECC region has sufficient resources to meet its load, including reserve margins, but does not have excess capacity due to resource investments that have occurred since 2008. In the opposite case, when additional conventional resources are added to meet 2020 loads, we attempt to add the lowest-cost combination of baseload and peaking conventional resources to ensure that the region would have sufficient energy and capacity. New conventional generation, if needed, is made without regard to the resources' carbon intensity. The choice between coal and natural gas depends on state law, with those states and provinces that prohibit new coal investment (CA, WA, BC) building natural gas.

4. Add capital cost estimates for the new TEPPC resources.

For each resource added between 2008 and 2020, we calculate capital and fixed O&M costs to supplement the fuel and variable O&M costs provided by TEPPC. With several exceptions noted below, we base our capital cost estimates on a modified version of the capital costs used by the U.S. Energy Information Administration (EIA) in developing its Annual Energy Outlook 2007 forecast. Our modifications to the EIA technology characterizations are intended primarily to account for the dramatic inflation in power plant construction costs that has occurred in the last few years and to reflect regional differences in the construction costs. The costs and performance characteristics for each conventional generation technology is documented in a separate section: conventional hydro, natural gas CCGT, natural gas CT, conventional coal, coal IGCC with and without carbon capture and storage, and nuclear. For California combined-cycle gas turbines we use the CCGT costs adopted in the 2007 Market Price Referent. The comparison of CCGT costs is described in the CCGT section.

For renewable technologies, we benchmark the EIA costs to more recent and complete cost estimates from published studies. These are documented in separate working papers on renewable resources, costs, and performance: wind, biomass, geothermal, central station solar, and small hydro. The combined renewable resource availability and levelized costs by WECC zone are shown in the renewable supply curves section. Working papers document the fuel cost forecast, transmission integration costs including transmission interconnection, long-line transmission, and intermittent resource integration, and the generic assumptions about power plant financing, taxes, tax incentives, and other factors to develop levelized annual cost estimates for both conventional and renewable resources. The resulting range of levelized costs of both new conventional and new renewable technologies are summarized by WECC zone.

5. Calculate and allocate energy production and CO2 emissions.

After developing the load and resource inputs, we calculate energy and CO2 emissions for each resource for each reference case using a PLEXOS simulation run in 2020. This provides a benchmark for total emissions in the WECC. The results of the 2020 PLEXOS run are documented in the results section. The total emissions in the WECC are reported in order to track the potential for contract reshuffling between the reference case and the target case that is possible given the assignment of emissions to California load evident in the process described below.

We then calculate the total California electric sector CO_2 emissions. This is the sum of the emission associated with specified resources, unspecified imports assessed at 1100 lbs/MWh, and the unspecified California emissions. The California emissions in each reference case are presented in the benchmarking section.

We then allocate responsibility for energy costs and CO_2 emissions to LSE in several steps. At the conclusion, each LSE has sufficient energy and capacity to serve load and is allocated a share of CO_2 responsibility. The steps are as follows:

Step 1: Assign the 'specified resources' to each California LSE. 'Specified resources' are energy, capacity, costs and CO_2 emissions associated with output from generation either owned or under contract to an LSE. This includes specified resources both within California and outside of California. CO_2 emissions for owned or contracted resources are assigned to the LSE in proportion to their ownership shares or the contracted share of the plant's output. We assume contracts that expire before 2020 are not renewed.

Step 2: After the specified resources are assigned, each LSE has a gap between the specified resources and their energy and capacity needs. Each LSE is assigned a share of the system costs and CO_2 emissions sufficient to ensure that the LSE is in load-resource balance on both an energy basis and a capacity basis. This is done in several steps.

2a. Renewables. Assignment of new renewables (including energy, capacity, and cost) to California LSEs is done in proportion to the gap between the RPS target and the renewable energy that is specified by LSE. This assumption can be thought of as essentially REC trading within the state so that there is no locational preference for renewables of one utility over the other.

2b. Imports. The PLEXOS run for 2020 provides expected imports into California. Assignment of imports to LSE (including energy, capacity, and emissions responsibility and cost) is done in proportion to the remaining energy requirement not filled with specified resources and new renewables.

2c. Unspecified California Pool. Unspecified energy, capacity, and emissions are assigned to LSE proportionally to the net requirements by LSE. By definition, the remaining energy and capacity equals the combined gap after specified emissions, new renewables, and imports are accounted. In the reference case, the unspecified emissions from generation within California is assigned an emissions intensity equal to the average of the emissions for the unspecified generation. Although the Decision is to assign 1,100 lbs/MWh to unspecified emissions, even within California, since most all generation is cleaner than this level we are assuming that these generators will become specified by 2020.

The reference case costs, and emissions by LSE are documented in the results section.

3. Plexos Data Sources Documentation

No.	Data Category	Data Value	Current Source	Recommended (or Possible) Updated Source	Notes
	Loads				
1		- non-CA WECC zones	SSG-WI data, 9/2005		27 load zones outside of CA
2		- CA zones	CEC Staff Forecast Sept. 2005 (#1)	CEC Draft Staff Forecast June 2007 (#2)	
3		- CA utilities	none	CEC Draft Staff Forecast June 2007 (#2)	
4		- hourly load shapes per WECC zone	SSG-WI data, 9/2005		Based on 2004 historical data, 2004 peak in Sept.
5		- nodal distribution factors	SSG-WI data, 9/2005		One distribution factor per node per year
	Reserves				
6		- planning reserves	PLEXOS Solutions assumption	15% Planning Reserve including 5% demand response	Currently implemented on a WECC-area basis (4 areas) and based on Project Dependable Capacity (PDC)
7		- operating reserves	WECC MORC 2000 (#3)		Includes non-spin, spin, regulation-up, and regulation-down assumptions
	Demand-Side Resources				
8		- non-CA energy efficiency	SSG-WI data, 9/2005		Forecast is net of energy efficiency
9		- CA energy efficiency	CEC Staff Forecast Sept. 2005 (#1)	CEC Draft Staff Forecast June 2007 (#2)	Forecast is net of energy efficiency
10		- non-CA dispatchable	WECC 10-Year Plan 2005 (#4)	WECC 10-Year Plan 2006)	WECC assumptions on load management and interruptible resources are at the WECC area level
11		- CA dispatchable	CEC Staff Forecast Sept. 2005 (#1)	CEC Draft Staff Forecast June 2007 (#2)	
	Supply-Side Resources				
12		- exising and resources	SSG-WI data, 9/2005 (modified by PS)		All generic resources, or those with a planned online date of 2006-2008 that could not be verified, were removed
13		- heat rate data	SSG-WI data, 9/2005 (modified by PS)		Heat rate data for CC's and CA older plants were modified (#5)
14		- chronological parameters	SSG-WI data, 9/2005		
15		- fixed hourly profiles for hydro, wind, and solar	SSG-WI data, 9/2005		Hydro is currently not optimized since sufficient data are not available to accurate represent constraints and inter-dependance
	Fuel Costs				
16		- coal, bio, and geothermal prices	SSG-WI data, 9/2005	See Fuel Cost Document	
17		- natural gas burner-tip prices	PS internal	See Fuel Cost Document	Burner-tip price is at the plant including all variable commodity, distribution, and taxes
	Emission Rates				
18		- CO2 emission rates by fuel	CEC report (#6)	See Tab	Emission rates are by fuel so that the impact of plant efficiency on emissions can be accurately modeled
	Transmission				
19		- transmission lines, nomograms and properties	SSG-WI data, 9/2005		
20					
	Market Prices	may not be necessary, need to discuss with E3 ??			

Sources:

1. "California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005", (2005 CEC Demand Forecast), California Energy Commission, September, 2005, CEC-400-2005-034-SF-ED2, p. 1-6.
2. CEC Staff Draft Forecast, July 2007, Form 1.5a "California Energy Demand 2008-2018 Demand Forecast - Staff Draft, Net Energy for Load by Control Area (GWh)", p. 45 of 193, and CEC Staff Draft Forecast, July 2007, Form 1.5b "California Energy Demand 2008-2018 Demand Forecast - Staff Draft, 1-in-2 Electric Peak Demand by Control Area (MW)", p. 46 of 193..
3. "Minimum Operating Criteria", Western Systems Coordinating Council, August 2000, p. 2. http://www.caiso.com/docs/2000/11/06/2000110620043027340ex.html .
4. 10-Year Coordinated Plan Summary, Western Electricity Coordinating Council, June, 2005
5. CEC Aging Plant Report, Appendix A, Plant Data Sheets
6. 2005 Environmental Performance Report of California's Electrical Generation system (CEC-700-2005-016-AP-A, Table A-1)

4. Attributing Generator Emissions to LSEs

Importance of Generator Assignment to LSEs in the GHG Model

According to the CPUC decision on "Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector," retail providers (called here, load serving entities, or LSEs) will be assigned responsibility for the greenhouse gas (GHG) emissions associated with the electricity generated to serve its load. This decision by the CPUC means that it is critical to ascertain which LSE purchases power from which generator. This could be determined either through power purchases tied to specific power plants or fleets of power plants, or through ownership or partial ownership of generators. All other power purchased by a LSE from the grid would be deemed "unspecified" and would be attributed an average greenhouse gas emissions factor.

While the CPUC will be able to implement this GHG accounting method based on full knowledge of contractual data and actual purchases by retail providers, for this modeling effort we did not have access to such detailed or confidential information. The assignment of generation to load uses only publicly available contract and ownership data. We also faced the additional challenge of projecting into 2020 which LSEs were likely to purchase power from which generators. Therefore, the assignment of generators to LSEs in this model should be viewed as only one plausible scenario for 2020.

Recommended Approach

Ultimately, we did not find a single comprehensive, publicly available source of information for utility ownership and contracts with generators. We therefore used a combination of data sources and approaches to assign generators to LSEs. The steps involved in this process are described below:

1. We began by focusing on the out-of-state coal power plants for which we knew California utilities had ownership shares, and researched these generators individually. We assigned coal plants to LSEs based on their ownership share in the plant, taking into account the expiration of the contract where the information was available. We followed the same methodology for the two California nuclear power plants, and other out-of-state generation which California utilities have a long term stake in, such as Hoover dam. See Table 1 below for details.
2. The next step was to use the bilateral contracts reported in the 2007 IEPR S-5 supply filings to associate generators to LSEs, taking into account the expiration dates for contracts.
3. Next, generators that are directly owned by a California utility were assigned to that utility for both 2008 and 2020. In the case of the POUs, other than SMUD and LADWP, generators owned by a POU were assigned to the grouping of "NorthernOther" or "SouthernOther," based on the municipality's location.
4. Finally, the remaining generators located inside California, which had not been otherwise assigned to an LSE, were assigned to either a "Northern California power pool" or a "Southern California power pool" based on the location of the plant: north of SP15 or south of SP15. This designation will allow us to allocate PG&E and the other Northern utilities the average emissions factor from the Northern California

power pool to meet their loads. SCE, SDG&E, LADWP and the remaining Southern utilities will all be assigned the average emissions factor of the remaining Southern California power pool generators.

The combination of these approaches, meant that in 2008, about 54,600 MW of generation is assigned to LSEs, and the remaining in-state CA generators are assigned to either a Northern power pool or a Southern power pool, resulting in a total of approximately 69,000 MW of assigned generation in 2008.

Table 1. Out-of-State and Nuclear Generators assigned to LSEs

Generator	Unit #	Location	Fuel Type	CA Owner	2008 LSE Share %	2020 Contract Status
Boardman	**1**	Boardman, OR	Coal	SDG&E	15.0%	**Expires**
				Northern California Other (Turlock)	8.5%	**Expires**
				Total CA	**24%**	
Four Corners	**4 & 5**	Fruitland, NM	Coal	SCE	48.0%	
				Total CA	**48.0%**	**Same**
Hoover		Boulder City, NV	Hydro	Southern California Other	34.1%	
				LADWP	15.4%	
				SCE	5.5%	
				Total CA	**55.0%**	**Same**
Intermountain Power Project	**1 & 2**	Delta, UT	Coal	LADWP	48.6%	**Same**
				Southern California Other	30.3%	**Same**
				Total CA	**78.9%**	
Navajo Generating Station	**1,2 & 3**	Page, AZ	Coal	LADWP	**21.2%**	**Same**
Palo Verde		Wintersburg, AZ	Nuclear	SCE	15.8%	**Same**
	1,2 & 3			Southern California Other (SCAPPA)	1.9%	**Same**
				LADWP	9.7%	**Same**
				Total CA	**27.4%**	
Reid Gardner	**4**	Moapa, NV	Coal	Assigned to IOUs (CA DWR)	**67.8%**	**Expires**
San Juan	**3**	San Juan, NM	Coal	Southern California Other	**41.8%**	**Same**
San Juan	**4**	San Juan, NM	Coal	Northern California Other	28.7%	**Same**
				Southern California Other	10.0%	**Same**
				Total CA	**38.8%**	
Yucca		Yuma, AZ	Natural Gas	Southern California Other	**(97 MW)**	**Same**
San Onofre	**2,3**	San Clemente, CA	Nuclear	SCE	75.0%	**Same**
				SDG&E	20.0%	**Same**
				Southern California Other	5.0%	**Same**
				Total CA	**100.0%**	
Diablo Canyon	**1,2**	San Louis Obispo, CA	Nuclear	PG&E	**100.0%**	**Same**
Bonaza	**1**	Utah	Coal	City of Riverside	**(26 MW)**	**Expires**
Hunter	**2**	Utah	Coal	City of Riverside	**(26 MW)**	**Expires**

Discussion

It is often challenging to decide how to interpret contract data – contract terms are often contingent on conditions, may vary by season or month, and may be for firm or non-firm power or some combination of the two, among other contractual stipulations. To the extent possible, we simplified this information into a single number: LSE percentage share in a given power plant's nameplate capacity.

The discussion below describes how contracts with out-of-state coal plants, which expire between 2008 and 2020, are treated in the model.

a. Intermountain Power and LADWP

As of 1983, LADWP owns 48.617% of Intermountain Power Project (Intermountain or IPP). This contract does not expire until 2027, so this ownership share is clearly reflected in the GHG model in 2008 and 2020.

LADWP also holds an 18.168% entitlement share of Intermountain which is recallable under certain circumstances. However, LADWP reports in their 2006 Integrated Resource Plan (IRP) that they expect this excess power allotment will "decrease to zero by 2008, representing growth of Utah municipalities." This represents a decrease in LADWP's coal purchases of approximately 300 MW relative to 1990.[1] If the 18.168% were included in the model in 2008 and 2020, LADWP would hold responsibility for 66.8% of Intermountain's emissions and California's emissions would increase by approximately 2.4 million metric tones of CO2. Currently, the model does not attribute any emissions to California or LADWP from the 18.168% recallable entitlement share.

The LADWP 2006 IRP states that:

> "LADWP is entitled to receive 44.617% of the plant's capacity rating. LADWP has also purchased a 4% entitlement of the plant from Utah Power and Light. Both of these entitlements are valid until the 2027 contract termination date. In addition, LADWP can receive up to an additional 18.168% entitlement under the Excess Power Sales Agreement, however this percentage, or portions of this percentage, can be recalled from LADWP by other IPP participants, given certain defined advanced notices."
>
> "Over the last several years, some of the Utah municipal participants of the IPP have exercised their recall rights for IPP power. LADWP has been receiving approximately 300 MW from the Utah municipalities under an Excess Power Sales Contract since the start up of the project. In addition, the Utah municipalities have indicated an interest to construct a third IPP unit. LADWP has stated that it will not participate in the ownership of a new IPP unit 3. As this new Unit 3 begins operation, it remains to be seen if this will cause the Utah municipalities to change the amount of energy they may recall for Units 1 and 2."

b. Reid Gardner and California Department of Water Resources

Since 1983, the California Department of Water Resources (CA DWR) has owned 67.8% of Reid Gardner Power Plant unit 4, a coal-fired facility near Las Vegas, Nevada.[2] This contract expires in 2013, and the CA DWR has indicated that they will not renew the contract.

In the model, we therefore assume that California is assigned 67.8% of Reid Gardner Unit 4, and that in 2020 California is not directly responsible for the emissions from this plant.

Furthermore, we attribute California's share of Reid Gardner's emissions to the three investor-owned utilities in 2008, based on the CEC's Staff Revised Forecast of electricity

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[1] LADWP 2006 Integrated Resource Plan, Appendix A, See page A-4 and Table A-2 on page A-7. Available at: http://www.ladwp.com/ladwp/cms/ladwp008065.pdf

[2] California Department of Water Resources, "Management of the California State Water Project" Bulletin 132-05, Chapter 1, page 8: http://www.swpao.water.ca.gov/publications/bulletin/05/Bulletin132-05.pdf

demand (MWh in 2008). This method of allocating Reid Gardner's emissions to LSEs is an approximation, since we do not know exactly to whom in California the Department of Water Resources will sell its Reid Gardner power.

c. Boardman and SDG&E and Turlock Irrigation District

San Diego Gas and Electric (SDG&E) and Turlock Irrigation District (TID) both have contracts with Boardman power plant, a coal-fired facility in Boardman, Oregon, which expire before 2020. According to SDG&E's and TID's filings to the CEC 2007 Integrated Energy Policy Report (IEPR) for electricity resource planning (form S-5), SDG&E's (15% of Boardman) contract expires in 2013 and Turlock's contract (approximately 8.5% of Boardman) expires in 2018. In the model, Turlock's emissions are grouped together with the "Other Northern utilities."

d. Bonanza Unit 1 and Hunter Unit 2 and City of Riverside

According to the City of Riverside's filing for the CEC 2007 Integrated Energy Policy Report (IEPR) electricity resource planning (form S-5), Riverside holds a 52 MW contract with the out-of-state coal plants Bonanza Unit 1 and Hunter Unit 2. This contact expires in 2010. In the model, we assign Riverside's emissions to the LSE category of "Other Southern California utilities." The Southern Other utilities therefore have responsibility for the portion of the emissions from these two coal plants in 2008, but not in 2020.

Sources Consulted

- Bilateral contracts and peak demand forecasts for the CEC 2007 Integrated Energy Policy Report (IEPR) for purposes of electricity resource planning (forms S-2 and S-5).
- "Scenarios Analysis of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report", CEC, June 2007.
- "Proposed Methodology to Estimate the Generation Resource Mix of California's Electricity Sector Imports," CEC, May 2006.
- "Revised Methodology to Estimate the Generation Resource Mix of California's Electricity Sector Imports," CEC, March 2007, and PowerPoint presentation for "California Energy Commission and Public Utilities Commission Workshop on Reporting and Tracking Greenhouse Gas Emissions for a Load-Based Cap," April 12 and 13, 2007.

California Utility Stakes in Coal, Nuclear and Out-of-State Generators:

- Boardman: For SDG&E contractual entitlement see: http://www.sdge.com/sunrisepowerlink/info/filings/Purpose_and_Need_Filing.pdf For Turlock's ownership share, see: http://www.publications.ojd.state.or.us/TC4032.htm
- Four Corners: Public Service New Mexico, see: http://www.pnm.com/systems/4c.htm
- Hoover Dam: US Dept. of Interior, Bureau of Reclamation, Lower Colorado Region, "Frequently Asked Questions," see: http://www.usbr.gov/lc/hooverdam/faqs/powerfaq.html

- Intermountain Power: Intermountain Power Agency, see: http://www.ipautah.com/aboutus.htm and see LADWP's 2006 "Integrated Resource Plan", Appendix A-4, Generating Resources, http://www.ladwp.com/ladwp/cms/ladwp008065.pdf
- Navajo: LADWP 2006 "Integrated Resource Plan", Appendix A-5, Generating Resources, http://www.ladwp.com/ladwp/cms/ladwp008065.pdf
- Palo Verde: Public Service New Mexico, see: http://www.pnm.com/systems/pv.htm.
- Reid Gardner: the California Department of Water Resources ownership in Unit 4 is assigned to the three California IOUs in proportion to their 2008 load, as projected by the CEC. For CADWR ownership in Reid Gardner see "Management of the California State Water Project" Bulletin 132-05, Chapter 1, page 8: http://www.swpao.water.ca.gov/publications/bulletin/05/Bulletin132-05.pdf
- San Juan: http://www.pnm.com/systems/sj.htm
- Yucca: http://www.iid.com/Media/IID-2006-Integrated-Resource-Plan.pdf
- San Onofre: http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/sanonofre.html
- Diablo Canyon: http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/diablo.html

5. Ensuring Sufficient Resources to Meet Loads

Introduction

The buildup of each reference case and target case starts with 2008 loads and the resources from WECC-wide databases. Loads are grown from levels in the 2008 SSG-WI database to 2020 using regional energy and peak load growth rates. Resources from the 2017 TEPPC database are tallied, and "preferred" (renewable or low-carbon) resources are then added in each WECC region until policy requirements such as renewables portfolio standards are met. Depending on the quantity and type of preferred resources that are added, it may be necessary to add conventional resources to ensure that each WECC region has sufficient energy and capacity to serve load reliably at the lowest cost. This paper describes E3's methodology for adding resources to ensure that each region has sufficient baseload and peaking resources in 2020.

Reference Case 2020 Loads and Resources

The buildup of each case starts with 2008 energy requirements and peak loads from the SSG-WI database, and 2008 resources from the TEPPC database.[3] Table 1 shows the load-resource balance in 2008 for each of the 12 WECC regions in the model. The table indicates that some WECC regions, particularly California and Utah-Southern Idaho, do not have sufficient capacity to meet a 15% reserve margin in 2008 in the absence of imports from other regions. This is due partly to inter-regional transfers and partly to E3's choice of regional boundaries. The Utah-Southern Idaho region, for example, relies on transfers of surplus generation from Wyoming, and in fact the PacifiCorp East control area spans portions of all three states. California relies both on imports of hydropower from the Northwest and thermal resources from the Southwest, some of which are owned by or contracted to California utilities.

Table 1. 2008 Load-Resource Balance by Region

TEPPC 2008 Total (Nameplate MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Bio	87			756		31	12		23	322	7		*1,238*
Coal	5,664	8,384		2,206		6,574	2,511	2,037	565	1,966	5,813	2,484	*38,204*
Gas	4,486	20,163	1,639	42,368	2,049	4,977	54	2,559	1,206	7,742	2,282	617	*90,143*
Geotherm				1,884	699				118			24	*2,725*
Hydro	674	3,975	21,998	12,648		1,873	693	42		30,484	2,504		*74,892*
Negative Bus Load				(61)		(45)	(148)	(243)	(9)		(43)		*(549)*
Nuclear		4,137		4,340						1,160			*9,637*
Oil		317		519	111	120				98		42	*1,207*
Pumping Load				(2,285)									*(2,285)*
Renewable				98			65			38			*201*
Solar				571									*571*
Wind	556			1,706		862	208	240	50	2,148	135	104	*6,008*
Total Dependable Capacity	*10,803*	*36,181*	*19,237*	*62,884*	*2,860*	*13,199*	*3,059*	*4,398*	*1,906*	*35,823*	*10,069*	*3,172*	*203,591*
2008 Loads	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Peak Load (MW)	8,570	20,560	9,950	61,428	1,645	11,041	1,620	3,290	1,737	29,395	10,157	2,526	*161,918*
Peak Load with 15% Reserve Margin (MW)	9,856	23,644	11,443	70,642	1,892	12,697	1,863	3,784	1,998	33,804	11,681	2,905	*186,206*
2008 Capacity Balance (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Surplus (Deficit)	948	12,537	7,795	(7,758)	968	502	1,196	615	(92)	2,018	(1,611)	268	*17,385*

Table 2 shows resource additions from 2008-2020 in the Current Policy Base Case. The first section shows resources in the TEPPC database with online dates in 2008 or later. A total of 17,000 MW are added in the WECC between 2008 and 2017. The second section shows

[3] The Transmission Expansion Planning Policy Committee (TEPPC) of the WECC (Western Electricity Coordinating Council) has produced a database of forecast loads, generation, and transmission in the WECC out to the year 2017. The Seams Steering Group-Western Interconnect (SSG-WI), the predecessor of TEPPC, produced the previous version of this database.

renewable resources added by E3 to ensure that each region meets its renewables targets (see "RPS Requirements" paper). E3 adds a total of 25,783 MW to the 2017 TEPPC resources. The third section of the table shows growth in peak loads between 2008 and 2020. The table shows that peak loads grow by approximately 36,600 MW in the WECC.

Table 2. 2008-2020 Additions, Existing Policy Base Case

TEPPC 2008-2017 Additions (Nameplate MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Bio											3		*3*
Coal	920	2,800				780	350				1,075	667	*6,592*
Gas	135	624		2,311	575	865	322	494	514	1,466			*7,306*
Geotherm									144		10		*154*
Hydro			935									3	*938*
Negative Bus Load													-
Nuclear													-
Oil													-
Pumping Load													-
Renewable													-
Solar													-
Wind	60			375		75					100		*610*
Total	*1,115*	*3,424*	*935*	*2,686*	*575*	*1,720*	*672*	*494*	*658*	*1,466*	*1,188*	*670*	*15,602*
E3 Renewable Additions (Nameplate MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Biogas	-	33	50	-	-	59	-	18	-	88	-	-	*248*
Geothermal	-	-	185	1,732	-	-	-	-	24	140	-	-	*2,081*
Hydro - Small	-	-	253	-	-	-	25	-	-	65	45	-	*388*
Solar Thermal	-	3,831	-	-	-	-	-	-	-	-	-	-	*3,831*
Wind	2,655	1,481	2,236	5,249	-	2,592	80	917	-	3,684	208	133	*19,235*
Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	*2,655*	*5,345*	*2,724*	*6,981*	-	*2,651*	*105*	*935*	*24*	*3,977*	*253*	*133*	*25,783*
2008-2020 Peak Additions (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Peak Load Growth	2,125	7,047	1,571	9,904	1,071	3,342	268	1,034	436	5,261	3,539	1,008	*36,605*
Dependable Capacity Additions Required with 15%	2,443	8,104	1,807	11,389	1,231	3,843	308	1,189	502	6,050	4,070	1,160	*42,096*

Note: E3 made one revision to the TEPPC database, removing the 1700 MW Ely coal plant proposed for Nevada. E3 removed this resource because the TEPPC database shows that the Nevada region has sufficient resources in 2020 without the plant.

Methodology for Adding Resources

The ability to transfer energy and capacity from one region to another makes it difficult to construct a traditional load-resource balance for each of the WECC regions as we have defined them. Neighboring control areas frequently share reserves, and load diversity among the different WECC regions allows seasonal transfers of both energy and capacity, reducing the amount of resources that individual regions would otherwise be required to maintain. Constructing a load-resource balance by region would require making assumptions about the availability and regulatory treatment of imported power for meeting peak loads.

Moreover, hydro-rich regions such as the Pacific Northwest and British Columbia are energy constrained, rather than capacity constrained. Planning criteria in those regions address the issue of ensuring that sufficient energy is available to refill reservoirs to meet load under sustained cold temperatures late in the winter when water levels are at their lowest, rather than ensuring there is sufficient capacity to meet the highest hourly peak loads. Any meaningful load-resource balance for those regions would need to take this into consideration, multiplying the difficulty of the exercise. Finally, simple summations of nameplate generating capacity may be misleading, because it is difficult to ascertain if the TEPPC database accurately represents the peak availability of some 1,800 generating resources in the WECC.

For these reasons, we do not attempt to construct a traditional load-resource balance for each WECC region. Rather, we maintain reserve margins at their 2008 levels by adding new resources to meet peak load growth plus a 15% reserve margin in each region. That is, for each MW of growth in peak demand, we add 1.15 MW of dependable capacity in each region. Thus, 42,000 MW of dependable capacity must be added in the WECC in order to serve the forecast 36,600 MW of load growth by 2020 in order to avoid allowing reserve margins to deteriorate. All resources are counted at 100% of nameplate capacity for the purpose of calculating the 15% planning reserve margin, with the exception of wind, which is counted at 5% of nameplate capacity. Pumping load is assumed to drop to zero during system peaks.

Table 3 shows the load-resource balance for each region before adjustments are made to ensure sufficient resources. The table shows that the WECC as a whole has approximately 14,000 GWh of surplus energy in 2020, although several individual regions are shown to have an energy deficit, particularly the Northwest and Utah-Southern Idaho. The WECC requires approximately 20,000 MW of additional capacity, beyond the TEPPC and E3 additions, in order to ensure that each region can serve peak load with no deterioration in reserve margins.

Table 3. 2020 Load-Resource Balance by Region, Before Adjustments

Energy from New Resources (GWh)	AB	AZ	BC	CA	CFE	CO	MT	NM	NV	NW	UT	WY	*WECC Total*
Resources Added by TEPPC	8,098	25,784	3,811	19,352	4,554	11,545	4,966	3,704	14,857	10,736	8,201	5,075	*120,683*
Resources Added by E3	7,229	17,327	10,533	33,998	-	8,357	420	3,151	189	13,144	939	469	*95,756*
Total Energy Added	*15,327*	*43,111*	*14,344*	*53,350*	*4,554*	*19,902*	*5,386*	*6,855*	*15,046*	*23,880*	*9,140*	*5,544*	*216,438*
2008-2020 Load Growth (GWh)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
2008 Energy Load	59,910	97,454	66,345	298,945	8,942	67,600	10,293	19,913	10,351	177,186	55,549	14,581	*887,068*
2020 Energy Load	75,526	136,953	78,653	345,566	15,521	85,730	11,994	25,692	12,895	208,898	70,502	21,142	*1,089,073*
Total Energy Load Growth	*15,616*	*39,498*	*12,307*	*46,622*	*6,580*	*18,130*	*1,702*	*5,779*	*2,543*	*31,712*	*14,954*	*6,561*	*202,005*
2020 Energy Balance (GWh)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Surplus (Deficit)	(289)	3,613	2,036	6,728	(2,026)	1,772	3,684	1,075	12,503	(7,833)	(5,814)	(1,017)	*14,434*
Additional Energy Required	289	-	-	-	2,026	-	-	-	-	7,833	5,814	1,017	*16,978*

Capacity from New Resources (GWh)	AB	AZ	BC	CA	CFE	CO	MT	NM	NV	NW	UT	WY	*WECC Total*
Resources Added by TEPPC	1,058	3,424	935	2,330	575	1,648	672	494	658	1,466	1,093	670	*15,023*
Resources Added by E3	133	3,938	600	1,994	-	189	29	64	24	477	55	7	*7,509*
Total Resources Added	*1,191*	*7,362*	*1,535*	*4,324*	*575*	*1,837*	*701*	*558*	*682*	*1,943*	*1,149*	*676*	*22,532*
2008-2020 Load Growth (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
2008 Peak Load	8,570	20,560	9,950	61,428	1,645	11,041	1,620	3,290	1,737	29,395	10,157	2,526	*161,918*
2020 Peak Load	10,695	27,607	11,521	71,332	2,716	14,382	1,888	4,324	2,173	34,656	13,696	3,534	*198,523*
Total Peak Load Growth	*2,125*	*7,047*	*1,571*	*9,904*	*1,071*	*3,342*	*268*	*1,034*	*436*	*5,261*	*3,539*	*1,008*	*36,605*
Total Peak Load Growth, with 15% Reserves	*2,443*	*8,104*	*1,807*	*11,389*	*1,231*	*3,843*	*308*	*1,189*	*502*	*6,050*	*4,070*	*1,160*	*42,096*
2020 Capacity Balance (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Surplus (Deficit)	(1,252)	(742)	(272)	(7,065)	(656)	(2,006)	393	(631)	180	(4,107)	(2,921)	(484)	*(19,563)*

To fill this resource gap, we add a combination of new CCGT, SCGT and demand response resources according to the following procedure:

1. <u>Add baseload resources to meet the 2020 energy gap in each region.</u> Some WECC regions do not have sufficient energy production capability to meet annual energy needs in 2020. For these regions, we add CCGT units to meet energy needs.

2. <u>Calculate remaining capacity gap.</u> We next calculate how much baseload *capacity* is added to meet the energy needs for each region, assuming an annual capacity factor of 65% for CCGT resources. We then calculate the remaining capacity gap by subtracting the CCGT resources added from the capacity required to meet each region's load growth.

3. <u>Add demand response resources.</u> We next add demand response resources to meet California's policy goal of 5% of peak load. Demand response resources change the load profile by reducing peak loads, but they do not result in a reduction in annual energy requirements.

4. <u>Add CCGT or SCGT resources to meet remaining capacity gap.</u> Finally, we add either CCGT or SCGT resources to meet any remaining capacity gap. We add CCGT resources in hydro-rich regions, including the Pacific Northwest, British Columbia and Montana. We add SCGT resources in all other regions.

Table 4 shows the conventional resources that are added using the above procedure. After adding baseload resources to meet the energy gap, only four regions require additional peaking resources. These regions are California, Colorado, New Mexico and Utah-Southern Idaho.

Table 4. Resources Added to Ensure that Each Region has Sufficient Energy and Capacity

Resources Added to Fill Remaining Gap	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Gas CCCT Resources Added (MW)	51	-	272	-	356	-	-	-	-	4,107	1,021	179	*5,985*
Demand Response				3,567									*3,567*
Gas CT Resources Added (MW)	1,202	742	-	3,499	301	2,006	-	631	-	-	1,900	305	*10,585*

Table 5 shows the final load-resource balance for each WECC region. Each region has at a net energy surplus that is at least as high as the 2008 value. The capacity surplus in Montana and Nevada is slightly higher than the 2008 value, because the combination of the TEPPC resource additions and the E3 renewable resource additions are sufficient to increase the capacity surplus without adding any additional conventional resources.

Table 5. Final 2020 Load-Resource Balance by Region, Business-as-Usual Reference Case

Total 2020 by Type	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Bio	87	33	50	756	-	90	12	18	23	410	10	-	*1,489*
Coal	6,584	11,184	-	2,206	-	7,354	2,861	2,037	565	1,966	6,888	3,151	*44,796*
Gas	5,873	21,529	1,911	48,178	3,280	7,847	376	3,683	1,720	13,315	5,203	1,101	*114,018*
Geotherm	-	-	185	3,615	699	-	-	-	286	140	10	24	*4,960*
Hydro	674	3,975	23,186	12,648	-	1,873	718	42	-	30,549	2,549	3	*76,217*
Negative Bus Load	-	-	-	(61)	-	(45)	(148)	(243)	(9)	-	(43)	-	*(549)*
Nuclear	-	4,137	-	4,340	-	-	-	-	-	1,160	-	-	*9,637*
Oil	-	317	-	519	111	120	-	-	-	98	-	42	*1,207*
Pumping Load	-	-	-	(2,285)	-	-	-	-	-	-	-	-	*(2,285)*
Renewable	-	-	-	98	-	-	65	-	-	38	-	-	*201*
Solar	-	3,831	-	571	-	-	-	-	-	-	-	-	*4,402*
Wind	3,271	1,481	2,236	7,331	-	3,529	288	1,157	50	5,832	443	237	*25,854*
Demand Response	-	-	-	3,567	-	-	-	-	-	-	-	-	*3,567*
Total Dependable Capacity	*13,381*	*45,080*	*25,444*	*76,864*	*4,091*	*17,461*	*4,047*	*5,838*	*2,597*	*47,970*	*14,683*	*4,332*	*261,787*
2020 Peak Load (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Peak Load	10,695	27,607	11,521	71,332	2,716	14,382	1,888	4,324	2,173	34,656	13,696	3,534	*198,523*
Peak Load with 15% Reserve Margin	12,299	31,748	13,249	82,031	3,123	16,539	2,171	4,972	2,499	39,854	15,751	4,064	*228,302*
2020 Capacity Balance (MW)	**AB**	**AZ**	**BC**	**CA**	**CFE**	**CO**	**MT**	**NM**	**NV**	**NW**	**UT**	**WY**	***WECC Total***
Surplus (Deficit)	1,083	13,332	12,194	(5,168)	968	922	1,876	866	98	8,115	(1,067)	268	*33,486*

6. Calculating the Total Cost of Electricity Service

This paper describes the methodology used in the GHG Calculator to calculate the total cost of electricity service under a given case. The total cost of electric service is the sum of all fixed and variable costs associated with each of the demand-side and supply-side resources selected in the case. The methodology for calculating total cost therefore integrates all of the cost and data assumptions that are used in the modeling and described in other papers. The formula for calculating the total cost of electricity service is:

$$TC = FC_S + FC_D + VC + TXC + WIC$$

where:

FC_S = Fixed cost of new supply-side resources, levelized
FC_D = Fixed cost of new demand-side resources, levelized
VC = Variable cost of existing and new resources
TXC = Cost of new transmission, levelized
WIC = Cost of integrating wind resources

Each of the cost categories listed above is composed of a number of individual components, each of which is described in another paper (see the "Resource, Cost, and Performance Assumptions" papers for each of the generation technologies included in the GHG calculator, and the "Transmission Costs" paper). We provide a brief overview here to familiarize the reader with the general methodology for calculating the total costs.

Cost Categories

Fixed costs of new supply-side resources

The fixed costs of new supply-side resources depend on the resources selected for each case. Some resources have high initial costs and lower ongoing costs, while others are less capital-intensive initially but have higher operating costs. Fixed costs include fixed operation and maintenance costs, overnight capital and construction costs, interest on funds used during construction, financing costs including both interest payments and shareholder returns, taxes, and insurance.

Fixed costs of new demand-side resources

Similar to supply-side resources, demand-side resources require upfront investment that must be incorporated into utility rates. Fixed costs of new demand-side resources include the incremental cost of energy-efficient equipment, installation costs, construction costs, and the cost of customer incentives.

Variable cost of existing and new supply-side resources

The model incorporates the variable cost of both existing and new resources. Variable costs include principally fuel and variable operations and maintenance costs. Some demand-side resources may also have variable costs. Demand response resources, in particular, may be structured to include an incentive payment for each hour in which the resource is dispatched.

Cost of new transmission

New resources cannot be added to the system without upgrades to the regional transmission grid. The model tracks two types of transmission upgrade costs: (1) the costs of generation integration facilities or "collector systems" – transmission that is radial to the main transmission grid and that collects energy produced by generators and transmits it to a higher voltage, backbone facility; and (2) the costs of main grid upgrades or "trunk lines" – the higher voltage facilities necessary for transmitting large amounts of power over long distances. We assume that generation integration facilities are financed by the generation owner, while main grid upgrades use investor-owned utility financing.

Cost of integrating wind resources

Wind resources are intermittent and variable in nature. Output from wind energy facilities fluctuates from hour to hour, and even from minute to minute, depending on the speed of the wind as it flows over the turbines. The variable nature of the output imposes costs on the system, because the output of other resources must be constantly adjusted to match fluctuations in the output of the wind resources. These costs are small when wind resources make up only a small proportion of the total resources on the system, but can be substantial when wind reaches high levels of penetration. The GHG Calculator calculates the cost of integrating wind resources as a function of wind's share of the total resources in a control area.

7. 2020 Reference Case Input Assumptions
Summary

Introduction

E3 has developed two reference cases for the year 2020. These cases are the foundation from which AB 32 target scenarios are developed in Plexos, and are also the foundation for user-defined scenarios in the GHG calculator. Development of these cases required making assumptions about a number of important policy and modeling issues, many of which are the subject of ongoing proceedings within the joint agency GHG dockets. The assumptions used in the reference cases are described in the sections below.

The reference cases are referred to as the "business-as-usual" and "aggressive policy" cases. With regard to most policy and modeling issues, the input assumptions are the same. In a few key areas, such as those related to targeted sector policies on energy efficiency and the Renewables Portfolio Standard, significant differences were assumed. The purpose of having two reference cases is to span the likely range of policy mandates for the electricity sector in 2020, with "business-as-usual" representing the current level of implementation, and "aggressive policy" representing the most aggressive policies currently under serious discussion within the legislative and regulatory contexts.

Assumptions Common to Both Cases

The assumptions common to both the business-as-usual policy and aggressive policy reference cases are shown in Table 1 below. In some cases, issues will be addressed in Stage 2 of the GHG modeling process, beginning after the initial public workshop in November 2007. These are identified as "Stage 2" in the table. "TEPPC" refers to the assumptions contained in the WECC's 2017 TEPPC case.[4] "SSG-WI" refers to the assumptions contained in the WECC's 2008 SSG-WI case.[5]

Table 1. Assumptions common to business-as-usual and aggressive policy reference cases.

Issue	Assumption
California LSEs modeled	PG&E, SCE, SDG&E, LADWP, SMUD, Other No. CA, Other So. CA
Rest-of-WECC entities modeled	11 zones, not including California (zones described in separate report)
Point of regulation	Load based cap
Electricity sector 2020 emissions target	CARB 1990 inventory for electricity sector
LSE emission allowance allocation method	Stage 2

[4] The Transmission Expansion Planning Policy Committee (TEPPC) of the WECC (Western Electricity Coordinating Council) has produced a model of loads, generation, and transmission in the WECC for the year 2017. This is widely referred to as the TEPPC 2017 case.

[5] The Seams Steering Group-Western Interconnect (SSG-WI), the predecessor of TEPPC, produced a previous model of loads, generation, and transmission in the WECC for the year 2008.

Issue	Assumption
Cross-sector trading	Stage 2
Offsets	Stage 2
Allowance banking	Stage 2
Allowance borrowing	Stage 2
Regional/federal trading system	Stage 2
RECs (renewable energy credits)	Implicitly assumed in cost-based model
Energy Efficiency	(different in each case, see Table 2)
RPS (renewables portfolio standard)	(different in each case, see Table 2)
Rest-of-WECC RPS	Existing RPS in states that currently have them, 5% RPS in states that currently do not
Demand Response	5% of peak demand for all IOUs, 0% for non-IOU LSEs
CSI (California Solar Initiative)	Existing CSI installation rates through 2020 (CEC Energy Demand Forecast 2008-2018)
Distributed Generation	Existing SGIP installation rates for both cases (CEC Energy Demand Forecast 2008-2018)
Natural gas generation additions in CA	As required for load & resource balance
Conventional zero-carbon generation (e.g., nuclear, coal with carbon capture and storage) additions in CA	None
Generation ownership assignment by CA LSE	Based on publicly available ownership data
Long-term contract assignment by LSE	Based on publicly available contract data, including contract expiration dates
Coal plant ownership/long-term contracts by California LSEs	All existing coal plant ownership maintained, long-term contracts end if known to expire before 2020 (Reid Gardner, Boardman, Bonanza-1, Hunter-2)
California generating plant retirements and repowering	Use TEPPC assumptions
Assignment of unspecified imports to LSEs	CPUC reporting decision (1100 lbs CO_2/MWh for all imports)
Assignment of California pool purchases to LSEs	Multiply Plexos unassigned in-state generation in Northern CA and Southern CA pools by LSE load proportion in those areas
CHP (combined heat and power) assignment of emissions to electricity sector	CARB inventory method
Generating plant emission factors	CARB fuel emission factors multiplied by TEPPC heat rates
Non-CO2 GHGs	Include only fugitive SF_6 from transmission & distribution system
Existing WECC loads, resources, transmission	Use SSG-WI assumptions
Load forecasts for LSEs	CEC forecast, extrapolated to 2020

Issue	Assumption
Load forecasts for Rest-of-WECC zones	Zonal growth rates from integrated resource plans, applied to 2008 SSG-WI loads
Cost of generation	(described in separate reports)
Cost of transmission	(described in separate report)
Fuel price forecast	CPUC MPR natural gas forecast (other fuels described in separate report)
Financing assumption in cost model	IPP (merchant) financing (details described in separate report)

Differences Between Business-as-Usual and Aggressive Policy Cases

Table 2 below shows the key difference between the business-as-usual and aggressive policy reference cases.

Table 2. Differences between business-as-usual and aggressive policy reference cases.

Issue	Business-as-Usual Reference Case	Aggressive Policy Reference Case
Energy efficiency in CA	100% of current market potential assumed to be embedded in CEC load forecast (described in separate report)	100% of net economic potential (described in separate report)
RPS (Renewables Portfolio Standard) in CA	20% of retail sales for all LSEs	33% of retail sales for all LSEs
Long-line transmission for out of state renewable purchases	Stage 2	Stage 2
Renewables additions for CA	(model results described in separate report)	(model results described in separate report)

8. Capital Cost, Finance, and Tax Assumptions

Cost Basis and Levelization

Costs for the Reference and Target cases in the GHG model are year 2020 costs (assuming a project achieves commercial operation in year 2020), expressed in levelized 2008 dollars.

Zonal Cost Multipliers

In the GHG model, a set of zonal multipliers is applied to the levelized capital and fixed O&M costs in each of the model's 12 WECC regions to reflect regional differences in land, labor and construction costs. These multipliers were obtained from the U.S. Army Corps of Engineers, Civil Works Construction Cost Index System (March 31, 2007), and are listed in Table A below. The zonal multipliers also apply to taxes and insurance costs.

Table A. Zonal Capital Cost Multipliers

Resource Zone Name	Capital Cost Factor
Alberta	1.00
Arizona-Southern Nevada	1.00
British Columbia	1.00
California	1.20
CFE (Baja California, Mexico)	1.00
Colorado	0.97
Montana	1.02
New Mexico	0.96
Northern Nevada	1.09
Northwest	1.11
Utah-Southern Idaho	1.00
Wyoming	0.92

Capital Cost Escalation

Escalation factors are applied to capital costs to adjust for historic and anticipated increases in costs from 2005-2008. For all technology types except natural gas CCGT, wind and solar thermal (CSP), the capital cost escalators are 25% in both 2005 and 2006, and 2.5% in 2007. For a CCGT, the model uses the 2008 capital cost from the 2007 CEC MPR model[6]. (See "New Generation Resources and Costs" reports). For solar thermal, the escalators are 2.5%

[6] 2007 Market Price Referent model (proceeding R. 04-04-026). See http://www.ethree.com/mpr.html.

in 2005 and 2007, and 5% in 2006. For wind, the escalators are 15% in 2005 and 2006, and 2.5% in 2007.[7] From 2009 to 2020, inflation is assumed to continue at 2.5% per year; the 2020 cost is then deflated at 2.5% to arrive at the real levelized cost in 2008 dollars. The generator interconnection cost is inflated by 2.5% from 2007. This cost is assumed to be part of the plant capital costs.

Asset Ownership and Financing Assumptions

The GHG calculator enables users to select their own financing assumptions. Users may choose IOU, municipal utility, or IPP ownership, and may also directly select the percentage of debt and equity in the capital structure, as well as the cost of debt and equity capital.

In the GHG model base case, the finance costs for new generation assets are based on IPP financing. There are several reasons why this is an appropriate base case assumption. Certain technologies have investment tax credit incentives available only to private sector developers. Assuming utilities will procure assets through a competitive bid process, an IPP plant may have a more aggressive financing structure and plant configuration, resulting in a lower bid price than a utility-build option. Lastly, due to utility ownership restrictions, IPP ownership may be more consistent with how resources are likely to be constructed in California, and provides a comparable basis on which to analyze resources contracted by both investor-owned and publicly-owned utilities.

The ownership assumption determines the capital reimbursement term, cost of capital, and tax benefits for each project. The GHG calculator then determines the all-in cost of each type of generation based on the project's required revenue level. The required revenue amount is determined such that the owner will receive its target after-tax equity return after all tax benefits have been applied. This means that the full amount of any tax benefit is passed on to ratepayers, either through the revenue requirement in the utility-owned case, or through the contract price in an IPP-owned case.

The GHG calculator incorporates two types of transmission: long-line network and gen-tie. The long-line transmission assets are assumed in all cases to be owned by the IOU so are financed using IOU assumptions. Gen-tie interconnection costs are assumed to be part of the project cost so are financed according to the project ownership assumption. The long-line transmission costs are not incorporated in the levelized $/MWh project cost but are added into the analysis to facilitate ranking projects.

Return Of and On Invested Capital

When utility ownership is selected, a book life and project life of 30 years is assumed for all resource types. Book depreciation is used to calculate the return of invested capital based on this 30-year term. Invested capital includes both direct capital costs and an allowance for funds used during construction (AFUDC), also known as interest during construction (IDC) in the IPP case. The current version of the GHG calculator uses a multiplier to approximate

[7] The difference between the capital escalation factors for different technologies is the time basis for the cost estimate used by E3. For most technologies, capital costs were adopted from the EIA's *2007 Annual Energy Outlook*, which were based on 2005 costs. For wind and solar thermal, more recent cost estimates were used that already incorporated some cost escalation. The detailed assumptions are provided in the reports on costs and resources for each individual generation technology used in the GHG model.

AFUDC; the next version will calculate AFUDC using the draw schedule and construction period assumptions from the CEC's Cost of Generation Model.[8] AFUDC is accrued at the utility pre-tax WACC rate. The front-end-loaded revenue requirements profile is modeled, and the annual return of and on capital is levelized at the post-tax nominal utility WACC over a 30-year period. This levelized cost, divided by the plant capacity, creates the $/kW charge for capital.

When municipal utility ownership is selected, assumptions are identical to the IOU case, except that municipal utility financing is assumed to be 100% debt and at a lower interest rate than available to IOUs. Levelization is also performed using the municipal utility WACC. Because municipal utilities do not pay income taxes, their pre- and post-tax WACC rates are the same.

When IPP ownership is selected, the return of and on capital is treated in much the same way, except that a project and book life of 20 years is assumed for the IPP ownership case. This assumption was made because it is likely that the maximum utility contract length would be 20 years, either through a 20-year contract or renewal of a 10-year contract. In this way, the term of the underlying debt can be matched to the return of capital in the revenue stream. Additionally, the IPP case assumes a mortgage-style capital repayment, rather than a revenue requirement-style. The IPP pre-tax WACC generates the IPP IDC amount using the same draw schedule as in the utility case. The return of and on capital is similarly levelized, but over a 20-year period using the post-tax nominal IPP WACC, then divided by the plant capacity to create the $/kW charge for capital.

The specific IPP finance assumptions used in the base case are listed in Table B below, along with the IOU and municipal utility assumptions. Note that the finance assumptions are the expected average values throughout the project term, commencing in 2020. Note also that the IPP finance assumptions are not reflective of an IPP selling its entire plant output into the market on a merchant basis, but instead assume all output is contracted under a high credit-quality utility offtake contract. The IPP debt rate assumption is 7.89%. This assumption incorporates additional project risk over the utility corporate debt rate assumption of 6.92%. The IPP equity return assumption of 15.8% is an average of the 15.7% value from the California State Board of Equalization's March 2007 Capitalization Rate Study and the 15.9% value recommended by the CEC. The 70:30 D:E capitalization is an expected achieved financial structure, assuming a high credit quality PPA offtake contract. These inputs result in an IPP pre-tax WACC of 10.26%, which is the value recommended by CEC for non-gas-fired power projects. The utility pre-tax WACC is 9.09%, based on average debt rates as of 12/31/2006 and most recently allowed ROEs for the three California IOUs (PG&E, SCE, and SDG&E).

[8] CEC, "Comparative Costs of California Central Station Electricity Generation Technologies," Draft Staff Report, CEC-200-2007-011-SD, June 7, 2007

Table B. Financing assumptions

General Inflation	2.50%			
Real fuel price inflation	3.00%			
Switch for IPP or Utility Owned (1=IOU, 2=Muni, 3=IPP)	3			
	Active	IOU	Muni	IPP
Tax Rate	41%	41%	0%	41%
Financing Life (years)	20	30	30	20
Cost of Equity	15.80%	11.25%	0.00%	15.80%
Equity Share in Capital Structure	30%	50%	0%	30%
Cost of Debt	7.89%	6.92%	6.50%	7.89%
Pre-tax nominal WACC	10.26%	9.09%	6.5%	10.26%

Taxes and Tax Incentives

For all types of ownership, income taxes are based on the levelized equity return, and are adjusted for any available tax incentives. The model assumes a 35% federal tax rate and an 8.84% state tax rate, resulting in a 40.7% marginal tax rate. Taxable income is calculated using book depreciation, adjusted for any accelerated tax depreciation and full tax benefit of interest. The model currently assumes no state-level accelerated depreciation tax benefits, as is the current case in California. Any production or investment tax credits are applied, and taxes are grossed up such that the owner achieves its target after-tax return on equity, . Taxes are levelized over the appropriate ownership term, then divided by the plant capacity to achieve a 2008 levelized $/kW charge. Property taxes are assumed to be 1% of the total project capital costs, and property tax amounts are also levelized.

Tax and Policy Incentives

Many of the generating technologies in the GHG calculator are eligible for a variety of tax breaks and other incentives from either the federal or state government. Currently available federal government tax benefits include investment tax credits (ITC), production tax credits (PTC), and accelerated depreciation. California state-level incentives include property-tax incentives and Supplemental Energy Payments. The model assumes that the state-level SEP and property tax incentives would no longer be available in 2020, nor would federal incentives with cumulative capacity limitations.

Other federal tax benefits are assumed to be permanently available at 2008 levels. Therefore, the current investment tax credit (ITC) is assumed to apply to geothermal and solar thermal assets in 2020, and the current production tax credit (PTC) is assumed to apply to biogas & biomass, large and small hydro, and wind projects. Table C below details current tax policy.

The calculator assumes that the investment tax credit will continue to be available only if a project is under IPP ownership, and that accelerated depreciation and PTC benefits would be available to both IOUs and IPPs. Because municipal utilities do not pay taxes, the cost of their projects is not impacted by tax benefits.

The ITC is applied to eligible project costs, therefore the calculator provides an input that allows users to reduce total capital costs by a multiplier to obtain the eligible project costs. In the base case, the model assumes that 75% of total project costs are ITC-eligible costs, and that the entire ITC is available in the first year. The term of the PTC is 10 years. The first year PTC amount is escalated by inflation over the 10-year term, then present-valued to 2008. Both ITC and PTC are also levelized in 2008 dollars.

Table C. Tax Incentives

Technology	Incentives: Federal	Incentives: CA State
Coal IGCC	20% ITC (limited to first 4 GW of new IGCC capacity);[1] Loan guarantees of up to 80% for qualifying technologies.[2]	None.
Coal IGCC w/ CCS	20% ITC (limited to first 4 GW of new IGCC capacity);[1] Loan guarantees of up to 80%.[2]	None.
Coal ST	*If advanced coal technology*: 15% ITC (limited to first 3 GW of new capacity);[1]	None.
Natural Gas CCCT	None.	None.
Natural Gas CT	None.	None.
Nuclear	1.8¢/kWh PTC (nominal $) for first 8 years of operation if in-service by 2020 (limited to first 6 GW of new capacity);[3] Loan guarantees of up to 80%.[2]	None.
Biogas & Biomass	*If closed loop biomass*: 1.9¢/kWh PTC (inflation-adjusted 2007$) for first 10 years of if in service by 2008, *If landfill gas, municipal solid waste or open loop biomass:* 1.0¢/kWh PTC for first 10 years of if in service by 2008.[4]	SEP eligible (if meets certain requirements)[7]
Geothermal	1.9¢/kWh PTC (inflation-adjusted 2007$) for first 10 years of operation if in-service by 2008[4] *OR* 10% permanent ITC[5]; Accelerated depreciation (5 year)[6]	SEP eligible[7]
Large Hydro	*For incremental addition at existing generator, or generation built at existing non-hydroelectric dam:* 1.0¢/kWh PTC (inflation-adjusted 2007$) for first 10 years if in-service by 2008[4]	None.
Small Hydro	1.0¢/kWh PTC (inflation-adjusted 2007$) for first 10 years if in-service by 2008[4]	SEP eligible if ≤30 MW and no increased water diversion[7]
Solar Thermal	30% ITC if in-service by 2008, 10% permanent ITC otherwise[5]; accelerated depreciation (5 year)[6]	100% property tax exemption[8]; SEP eligible[7]

Technology	Incentives Federal	CA State
Wind	1.9¢/kWh PTC (inflation-adjusted 2007$) for first 10 years of operation if in-service by 2008[4]; Accelerated depreciation (5 year)[6]	SEP eligible[7]

PTC= Production Tax Credit; ITC = Investment Tax Credit;
SGIP = Self Generation Incentive Program; RPS = Renewable Portfolio Standard
MSW = Municipal Solid Waste SEP = Supplemental Energy Payments

Sources and Footnotes

Federal Policy Incentives:

[1]***Investment Tax Credit (ITC) for IGCC and Advanced Coal Technologies:*** From the Energy Policy Act of 2005, Title XIII, Section 48A (Qualifying Advanced Coal Project Credit), and Section 48B (Qualifying Gassification Project Credit). ITC is limited to a national total of 4.125 GW for new IGCC capacity and to 3.375 GW for other advanced coal-based generation technologies. Funding is also limited to a total of $800 million in total ITCs for gasification, and $500 million in total ITCs for advanced coal technologies. Technologies to retrofit or re-power existing coal plants may also qualify as an advanced coal technology, provided that the fuel input is at least 75% coal. To be designated as an advanced coal project, new non-IGCC plants must have: (a) heat rate of 8530 Btu/kWh or better [subject to some adjustments] (b) SO2 removal of 99% or higher, (c) NOx Emissions of 0.07 lbs/MMBTU, (d) Particulate emission of 0.015 lbs/MMBTU, and (d) Mercury removal of 90% or higher. IGCC technologies used for generators using petroleum residue or biomass may also qualify for the gasification ITC. Application must be submitted to DOE by 2006 and online date must be within 7 years; ITC value is reduced proportionally for plants also receiving incentive loan guarantees.

[2]***Federal Loan Guarantees for Innovative Technologies:*** Coal facilities with IGCC or carbon sequestration, and certain advanced nuclear technologies may qualify for federal loan guarantees of no more than 80% of project cost under then Energy Policy Act of 2005, Title XVII, Section 1702-1704. IGCC plants must meet certain performance and emissions requirements to qualify, and have one of a number of defined innovative components, including a CO2-capture ready design.

[3]***Production Tax Credit (PTC) for Nuclear:*** From the Energy Policy Act of 2005, Title XIII, Section 45J (Credit for Production from Advanced Nuclear Facilities). "Advanced Nuclear" is deemed to be any nuclear reactor design approved by the Nuclear Regulatory Commission after 1993. The credit is limited to the first 6 GW of new nuclear capacity in the U.S., and is limited to $125 million per GW annually. If more than 6 GW are under construction before January 1, 2014, the production will be shared among the new reactors on a proportional basis (e.g., if 9 GW of new capacity are under construction by that date, the PTC will be set to 1.2¢/kWh (= 1.8¢/kWh * 6 GW / 9 GW). [Allocation described in EIA, "Assumptions to Annual Energy Outlook 2007", p. 88.].

[4]***Investment Tax Credit (ITC) for Solar, Geothermal:*** Also known as the business energy tax credit, from United States Code (USC) Title 26 (Internal Revenue Code), § 48. Expanded by

the Energy Policy Act of 2005, House Resolution (H.R.) 6, and extended to cover all installations before January 1, 2009 by the Tax Relief and Healthcare Act of 2006 (H.R. 6111), Section 207. Energy Policy Act of 1992 created a permanent 10% ITC for solar, geothermal, and qualifying biomass generation. Energy Policy Act of 2005 temporarily raised this ITC to 30% for solar technologies installed between 2006 and 2008. Credit is reduced if generation is subsidized by other state or federal level financing incentives.

[5]***Production Tax Credit (PTC) for Qualifying Biomass, Geothermal, Wind, and Hydro:*** Officially the Renewable Electricity Production Credit (REPC), from United States Code (USC) Title 26 (Internal Revenue Code), § 45. Originally enacted as part Energy Policy Act of 1992 to apply to installations of wind and qualifying biomass during or before 2001. Renewed for 2006-2007 under the Energy Policy Act of 2007, and extended to geothermal and qualifying hydro generation as well. Extended through end of 2008 under the the Tax Relief and Health Care Act of 2006 (H.R. 6111). "Closed-loop biomass" is defined as "any organic material from a plant which is planted exclusively for purposes of being used at a qualified facility to produce electricity." If the reference energy price exceeds 8 cents/kWh in the year, the PTC is reduced proportionally to as low as 3 cents/kWh.

[6]***Accelerated Depreciation:*** USC, Chapter 26, § 168 (2005). Under the Modified Accelerated Cost-Recovery System (MACRS), business can recover their investments more quickly through accelerated depreciation on solar, geothermal, wind and photovoltaic generation assets, reducing their corporate income tax. These renewable technologies are classified as "5-year property". For more information, see IRS Publication 946, IRS Form 4562: Depreciation and Amortization, and Instructions for Form 4562.

California Policy Incentives:

[7]***Supplemental Energy Payments (SEP):*** Facilities must be are new or repowered on or after January 1, 2002, and may receive payments for up to 10 years. RPS eligible generators that win contracts with IOUs in California can apply to the CEC to receive SEPs to cover the difference between the MPR (market price referent) and the accepted bid price, subject to funding availability.

[8]***CA Property Tax Exemption for Solar Systems:*** From CA Revenue & Tax Code § 73. AB1099 in 2005 extended this section to apply to all systems installed before January 1, 2009.

Further description of Federal and state policy incentives:
North Carolina Solar Center & Interstate Renewable Energy Council, *Database of State Incentives for Renewables & Efficiency* (February 2007 Update). http://www.dsireusa.org/Index.cfm?EE=0&RE=1

U.S. Energy Information Administration, "Assumptions to the Annual Energy Outlook 2007," Report # DOE/EIA-0554(2007), http://www.eia.doe.gov/oiaf/aeo/assumption/index.html.

9. Fuel Price Forecasts

Introduction

The cost of electric generator fuel is an important component of the overall cost of providing electricity service. The PLEXOS production simulation model requires fuel price inputs for each generator in the WECC in order to calculate a least-cost dispatch and the associated carbon emissions. Thus, the GHG Calculator must provide a price forecast for each fuel that is used by a generator in the WECC. These include natural gas, coal, distillate fuel oil, residual fuel oil, petroleum coke, landfill gas, wood, and uranium.

Methodology

The SSG-WI 2005 database contains a set of prices for each of the fuels listed above. Prices for coal and natural gas vary by region in the SSG-WI database, while the prices of the other fuels are uniform across the WECC. Rather than attempt to develop forecasts for each of these prices from scratch, E3's methodology benchmarks these prices against a credible fuel price forecast for the most important fuel for the purpose of GHG modeling: natural gas delivered to a generator in California. E3 uses the natural gas price forecast adopted by the California PUC in the 2007 Market Price Referent proceeding. E3 takes the MPR natural gas price forecast for 2020 as the price of natural gas delivered to a generator in California for the GHG Calculator in 2020. The value is \$8.79/MMBtu, expressed in 2020 nominal dollars. We calculate a ratio of this value and the SSG-WI 2005 value for California. The ratio is 1.616. We then apply the ratio to all fuel prices in the SSG-WI 2005 database. The result is a 2020 delivered price for each fuel in each WECC region.

There are two important assumptions that are implicit in this simple methodology: (1) all fuel prices grow at the same rate between 2005 and 2020, and (2) fuel prices at all locations grow at the same rate between 2005 and 2020. To test whether these assumptions are reasonable, E3 conducted a limited benchmarking exercise, comparing the result of this method with fuel price forecasts from other sources. Figure 1 below compares E3's natural gas price forecast to several other sources. The figure shows that E3's value, identical to the MPR value for 2020, is higher than the value forecast by EIA, and higher than the Pacific Northwest "Westside" value forecast by the Northwest Power and Conservation Council. However, the value is below the CEC forecast for 2017, prepared for the 2007 Integrated Energy Policy Report. Additional benchmarking was conducted during the MPR proceeding. Figure 2 shows that E3's natural gas price forecasts for other WECC regions are in line with other forecasts. Figure 3 shows E3's coal price forecasts. E3's coal price forecasts are perhaps a little higher than other forecasts. However, the cost of coal is a relatively minor component in calculating the cost of reducing greenhouse gases in California. Finally, Figure 4 shows that E3's biomass price forecast is slightly below the EIA values.

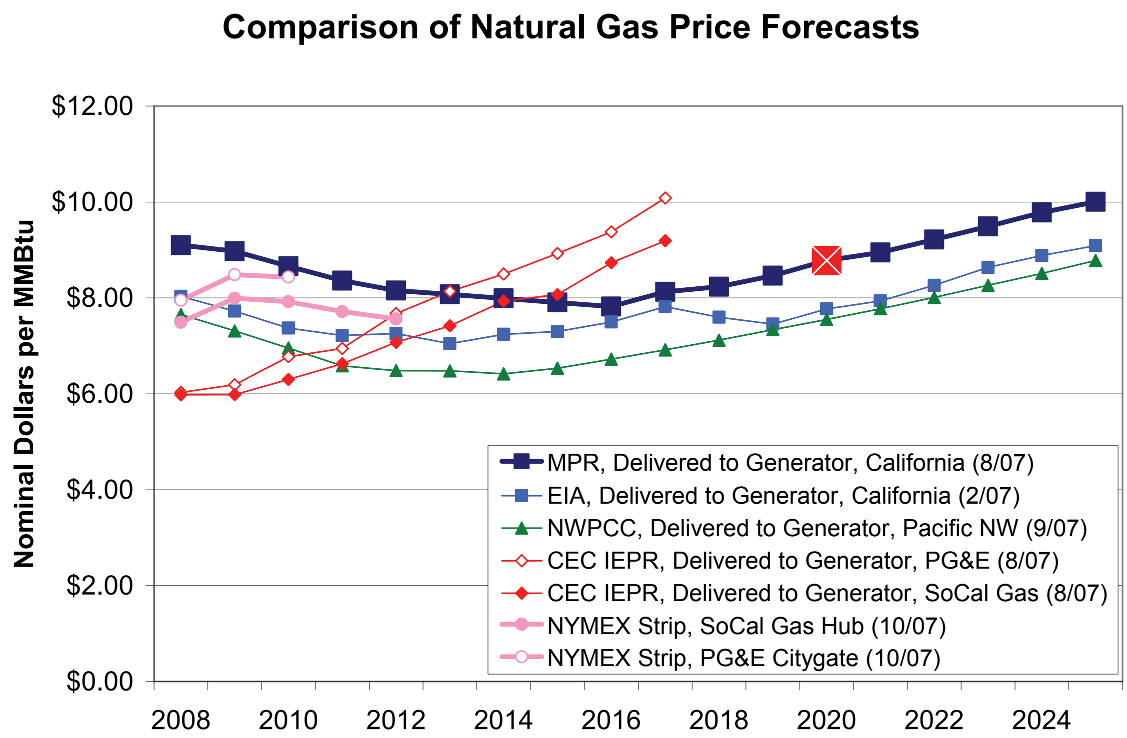

Figure 1

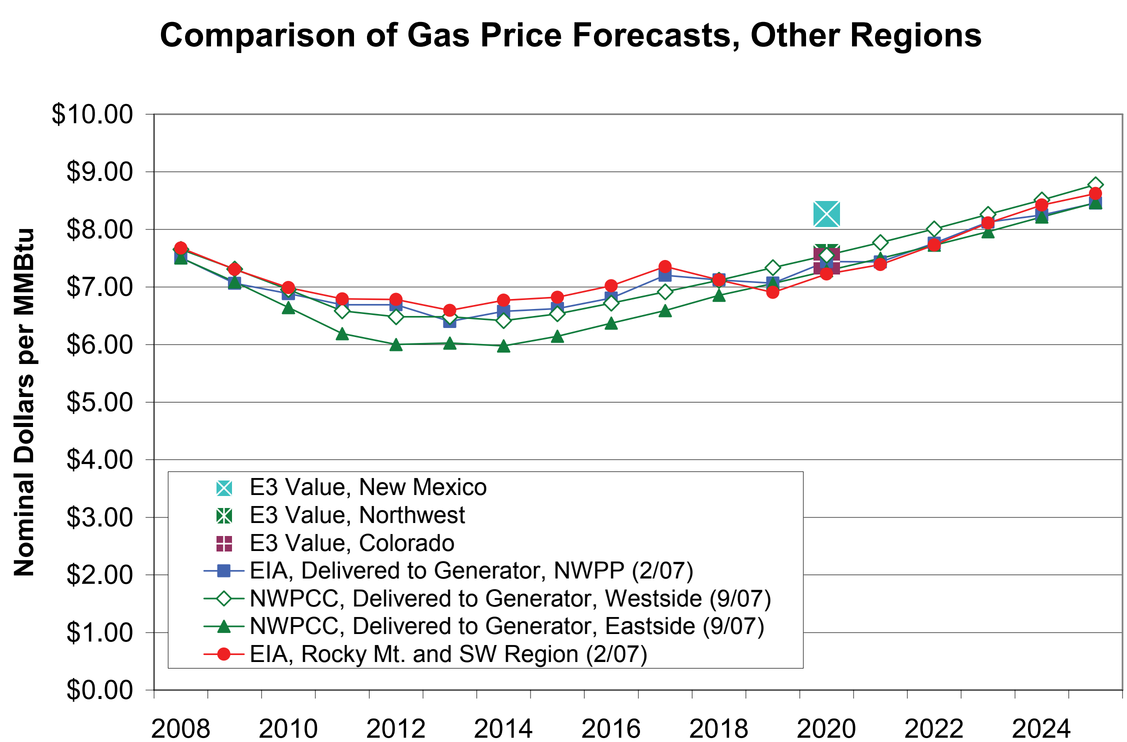

Figure 2

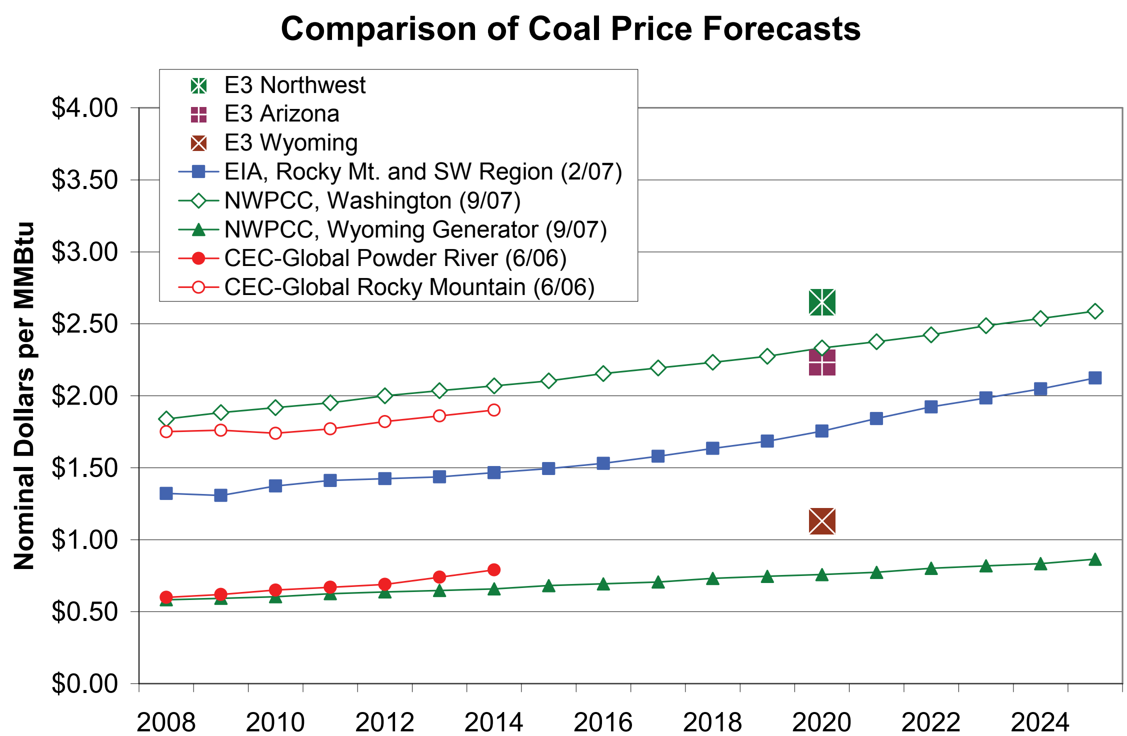

Figure 3

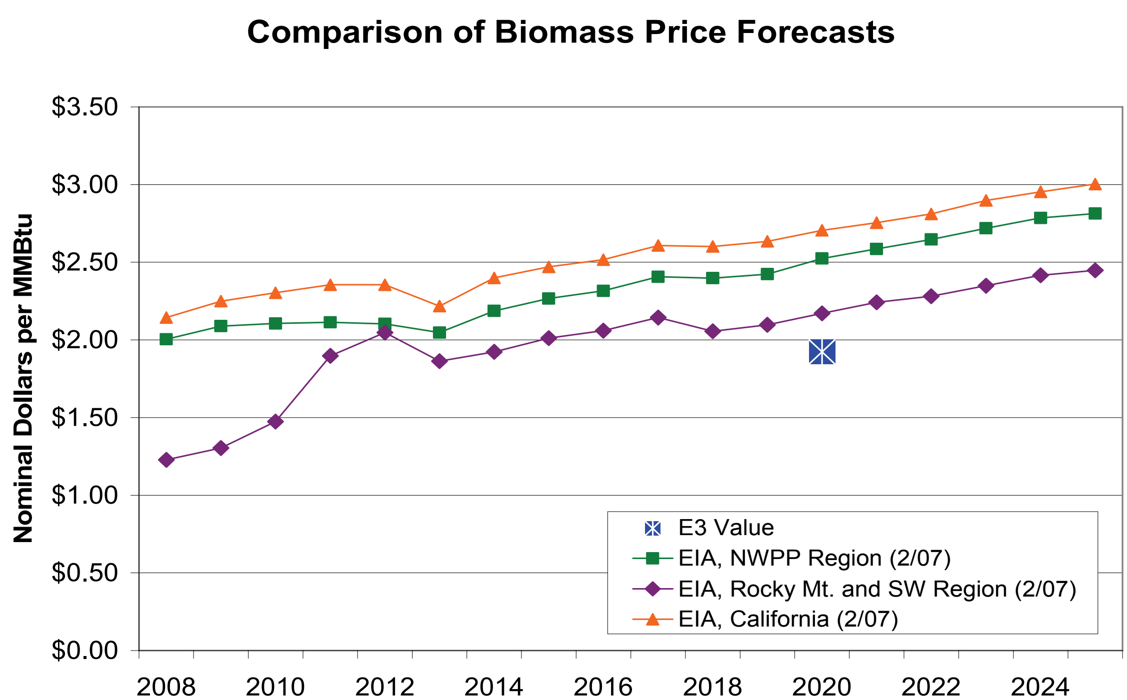

Figure 4

10. Renewable Portfolio Standards – Assumptions

Role of Renewable Portfolio Standards in the GHG Model

Many states in the West have legislated renewable portfolio standards (RPS), which generally require that a certain percentage of either the state, or investor-owned utilities' electricity sales must come from a renewable energy source. In the greenhouse gas (GHG) model, these RPS are used to determine the minimum amount of renewable energy that will be developed in the Western Electricity Coordinating Council (WECC) regions by 2020, based on the assumption that states will meet their RPS requirement.[9] This is important for the GHG model in two ways: (1) In 2020, the model assumes that California can import renewable energy from from other WECC regions only to the extent that the available renewable power is in excess of the region's own consumption. The RPS in each region thus represents the minimum level of self-consumption of renewable energy within that region. (2) In addition to specified imports of renewable energy where the supplier is known, California also imports electricity where the supplier is unspecified, and GHG emissions in some methodologies are assigned to LSEs based on the supply mix from the exporting region. The RPS level helps to determine the emission intensity of the regional mix.

Renewable Portfolio Standards by WECC Zone

Table 1 below describes the reference case assumptions for Renewable Portfolio Standards (RPS) included in the GHG analysis. RPS levels are developed for each of eleven WECC regions, plus California, used in this analysis. The eleven regions are chosen on the basis of transmission system topology, but also are generally consistent with state boundaries (see the "Load Forecast" report for more details about these regions).

Table 1 shows two values for each region. The first is a production-simulation model based estimate of existing renewable (RPS-qualifying) generation in 2008. The second value in Table 1 for each region is an RPS target for that region in 2020, which is used in the GHG model reference case. The final row of Table 1 shows a WECC-wide 2020 RPS target of 15 percent. This is the load-weighted average result for all eleven regions.

These RPS estimates are made by E3 on the basis of legislated targets and stated policy goals, and are adjusted to reflect the fact that some of the regions in the West combine portions of electricity load from several states with different RPS targets. In states where RPS legislation does not apply to all utilities, (for example, many states' RPS only apply to investor-owned utilities), the weighted 2020 targets reflect this distinction. The weighted RPS was calculated based on utility electricity sales data from the DOE Energy Information Agency 2005 Electric Sales and Revenue Report. A minimum standard of 5% is applied to jurisdictions where no current RPS exists, with the exception of CFE, Mexico, which is given an RPS of zero in 2020.

The important exception is California, where the GHG model "business-as-usual" reference case assumes that the 20 percent RPS applies to all utilities, including investor-owned and municipally-owned utilities, Community Choice Aggregators and Electric Service Providers.

[9] WECC refers to the electricity interconnection among the 13 western-most U.S. states plus the Canadian provinces of British Columbia and Alberta and northern Baja California.

Likewise, 33 percent RPS is assumed to apply to all utilities in the 'aggressive policy' reference case. Despite the fact that Senate Bill 107 requires that only the investor-owned utilities meet at least 20 percent of their sales with renewable energy resources by 2010, many of the municipally-owned utilities have set their own RPS targets at similar levels. Los Angeles Department of Water and Power (LADWP) aims to achieve a 20 percent RPS by 2010, and 35 percent by 2020.[10] Sacramento Municipal Utility District (SMUD) has set the goal of achieving a 20 percent RPS by 2011.[11] In addition, members of the Northern California Power Agency and many municipally owned utilities in Southern California have committed to reaching 20 percent RPS by 2017.[12] Given these commitments, it seems reasonable to set California's 'business-as-usual' reference case RPS at 20 percent in 2020. Likewise, the 'aggressive policy' scenario reflects the State's Energy Action Plan II, which calls for 33 percent renewable energy by 2020.[13] Table 1 below reflects the 20 percent RPS assumption for all of California in the 'business-as-usual' reference case.

Table 1. Current Renewable Energy Levels and 2020 RPS Target by Region

Region	2008 renewable energy share[6]	2020 reference case RPS target	Source	Notes
Alberta	7.5%	15.5%	Kralovic and Mutysheva, 2006	Alberta has a voluntary RPS goal and is assumed to meet this target by 2020.
Arizona-Southern Nevada	0.7%	13.2%	DSIRE 2007	Value is average of NV and AZ RPS targets, weighted by 2005 load in all of AZ and for the 3 southernmost utilities in NV (Boulder City, Harney Coop, & NV Power Company). NV RPS is 20% for 2015. Assumed constant through 2020. AZ RPS interpolated. RES requires utilities obtain (RECs) to meet 1.25% of their retail load 2006, rising to 15% by 2025.
British Columbia	0.0%	13.4%	2002 BC Energy Plan	2002 BC Energy Plan required electricity distributors to pursue a voluntary goal to acquire 50 percent of new supply from BC Clean Electricity over the next 10 years. Based on BC Hydro Electric load forecast, this would amount to 11.9% of BC total electricity sales after accounting for DSM.
CFE, Mexico	…	0.0%	…	Comision Federal de Electricidad in, Mexico is not assigned an RPS.
California	10.3%	20.0%	AB 107 and	Existing law requires investor

[10] See LADWP's Renewable Energy Policy website: http://www.ladwp.com/ladwp/cms/ladwp005864.jsp
[11] See the "2007 Status report on Renewable Energy at SMUD," http://www.smud.org/about/reports-pdfs/2007StatusRenewableEnergy.pdf
[12] See, for example, NCPA member Tom Habashi's testimony before the Senate Energy, Utilities and Communication Committee, February 6, 2007: http://www.sen.ca.gov/ftp/SEN/COMMITTEE/STANDING/ENERGY/_home/02-06-07NCPA.htm
[13] *California Energy Action Plan II: Implementation Roadmap for Energy Policies*, September 21, 2005, page 6.

Region	2008 renewable energy share[6]	2020 reference case RPS target	Source	Notes
			CA Energy Action Plan II	owned utilities to meet a target of 20% of retail sales by 2010. A 33% target is proposed in the CPUC/CEC Energy Action Plan II, but this has not yet been adopted into law or regulation. See discussion in the text for elaboration.
Colorado	7.4%	15.6%	DSIRE 2007	RPS differs for IOUs and electric cooperatives and municipal utilities: 20% for IOUs by 2020, and 10% for cooperatives and large munis (>40,000 customers) by 2020. This value is average for IOUs and coops and munis, weighted by 2005 electric sales (MWh).
Montana	10.1%	12.2%	DSIRE 2007	RPS applies to IOUs, with targets of 5% in 2008; 10% in 2010; 15% in 2015.
New Mexico	4.6%	15.8%	DSIRE 2007	Value calculated as average of 20% RPS for IOUs and 10% RPS for cooperatives by 2020, weighted by 2005 load.
Northern Nevada	9.9%	20.0%	DSIRE 2007	6% RPS in 2005, rising to 20% by 2015.
Northwest	9.6%	14.4%	DSIRE 2007	Value calculated as 2005 load weighted average of : 15% RPS for Washington by 2020 (only for utilities with >25,000 customers; represents 13% RPS based on large utilities share of 2005 load) and 5% to 20% RPS for Oregon by 2020 (varies by size of utility; 20% RPS for utilities with >3% of total state load; 10% RPS for utilities with 1.5-3% of total state load; 5% RPS for utilities with 1.5% of total state load.)
Utah-Southern Idaho	4.7%	5.0%	DSIRE 2007	No binding RPS currently for UT or ID. Base RPS has been assumed as 5%, the minimum regional value used in the model.
Wyoming	4.0%	5.0%	DSIRE 2007	No binding RPS currently for WY. Base RPS has been assumed as 5%, the minimum regional value used in the model.
WECC Total	7.6%	15%		Weighted average of the projected 2020 RPS standards within each zone.

[6]All 2008 values are calculated based the Western Electricity Coordinating Council's Transmission Expansion Planning Committee (TEPPC) generation commission date assumptions, TEPPC draft released in September 2007. Generators have been assigned to regions based on their known ownership and physical location. Hydro generation larger than 30 MW is not included.

Sources

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DOE Energy Information Agency 2005 Electric Sales and Revenue Report,
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http://www.iseee.ca/files/iseee/ABEnergyFutures-15.pdf

NC State University, "Database of State Incentives for Renewables & Efficiency (DSIRE)," June 2007 update. http://www.dsireusa.org/index.cfm?&CurrentPageID=7&EE=1&RE=1

11. CA LSE and WECC Load and Energy Forecasts

1. Importance of Load Growth Forecasts to the GHG Model

Load growth forecasts provide the basis for creating the resource expansion plan to 2020 within the model. Energy and peak demand growth determines how much new resources will be needed between 2008 and 2020. In this way, the magnitude of the load growth forecasts has implications for both total greenhouse gas emissions and the cost of reducing greenhouse gas emissions.

2. Recommended Values

a. California

California load serving entities (LSEs) load growth estimates were drawn from the CEC's California Energy Demand 2008-2018 Staff Revised Forecast.[14] The CEC's regions were mapped to the seven LSEs used in this study to find estimates of peak and energy demand in 2008 and 2020. The recommended values for load growth forecasts for the seven California LSEs are shown in Table 1 below, followed by the mapping of the CEC areas to the seven LSEs used in this analysis in Table 2.

Table 2. Recommended Peak and Energy Demand Forecasts for the California LSEs

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

[14] Staff Final Report, CEC-200-2007-015-SF, October 2007.

Table 3.

Mapping of CEC Areas of Analysis to the Seven California LSEs
1 PG&E
PG&E Bundled Customers
PG&E San Francisco
2 SCE
SCE Service Area Total
3 SDG&E
SDG&E Bundled Customers
4 SMUD
SMUD
5 LADWP
LADWP
6 Northern - Other
PG&E Direct Access
Northern California Power Agency
Silicon Valley Power
CCSF
Other Publicly Owned Utilities
Dept. of Water Resources - North
WAPA
Redding
Roseville
Shasta
Modesto Irrigation District
Turlock Irrigation District
Path 26 PG&E - South
Path 26 - Dept of Water Resources
7 Southern - Other
Anaheim Public Utilities District
Riverside Utilities Dept
Vernon Municipal Light District
Metropolitian Water District
Other Publicly Owned Utilities
Pasadena Water and Power Dept
SDG&E Direct Access
Dept of Water Resources - South
Burbank Public Service Department
Glendale Public Service Dept
Imperial Irrigation District Control Area

b. Rest of Western Region – Eleven Zones

For the eleven regions E3 defined in the rest of the West (called 'WECC regions' or 'Western regions'), the load forecast analysis relies on energy and peak demand growth rate forecasts from the integrated resource plans (IRPs) of the major Western state utilities and planning committees. These growth rates were applied to the 2008 SSG-WI loads estimated for the Western regions, to reach an estimate of 2020 loads in the Western regions (see Table 6 for the mapping between Western regions and SSG-WI zones). The recommended values for California and the eleven Western regions peak and energy load growth forecasts are shown in Table 3 below, followed by a description of the data sources for each growth rate estimate.

Table 4. Recommended Peak and Energy Demand Growth Rates for the Western Zones

Western Region	2008 Peak (MW)	2020 Peak (MW)	%	2008 Load (GWh)	2020 Load (GWh)	%
AB	8,570	10,695	1.9%	59,910	75,526	1.9%
AZ	20,560	27,607	2.5%	97,454	136,953	2.9%
BC	9,950	11,521	1.23%	56,877	67,444	1.43%
CA	62,946	73,738	1.3%	298,945	345,566	1.2%
CFE	1,645	2,716	4.3%	8,942	15,521	4.7%
CO	11,041	14,382	2.2%	67,582	85,707	2.0%
MT	1,620	1,888	1.3%	10,293	11,994	1.3%
NM	3,290	4,324	2.3%	19,913	25,692	2.1%
NV	1,737	2,173	1.9%	10,351	12,895	1.8%
NW	29,395	34,656	1.4%	177,186	208,898	1.4%
UT	10,157	13,696	2.5%	55,546	70,499	2.0%
WY	2,526	3,534	2.8%	14,579	21,139	3.1%
Total WECC	163,436	200,930	1.7%	877,576	1,077,835	1.7%

- Alberta Source: The Role of Renewable Energy in Alberta's Energy Future, November 2006. Figures represent the Alberta Internal Load ("AIL"); the total domestic consumption including behind-the-fence and City of Medicine Hat load. Growth rates are from the "most likely" scenario.

- Arizona's and Southern Nevada (Reno area) load growth estimates are based on an extrapolation from 2005 and 2015 load projection data provided by the Western Electricity Coordinating Council's 10-year Coordinated Plan Summary, July 2006. The WECC load forecast includes Arizona, New Mexico and Southern Nevada, so the numbers were adjusted to exclude New Mexico load. No data on peak demand growth was available from this source, so the peak demand growth rate is assumed to equal energy demand growth rate.

- British Colombia Source: BCHydro's Electric Load Forecast (2004/05 - 2025/26). British Columbia energy and peak demand forecasts include DSM measures.

- California Source: "California Energy Demand 2008-2018 Staff Revised Forecast," Staff Final Report, CEC-200-2007-015-SF, October 2007.

- CFE, Mexico Source: "Scenarios Analysis of the California Electricity System: 2007 Integrated Energy Policy Report," CEC 2007.

- Colorado Source: Public Service Company of Colorado, 2003 Least Cost Resource Plan. Growth rates are from data available for 2008 and 2015.

- Montana Source: NorthWest Energy 2005 Electric Default Supply Resource Procurement Plan. Peak demand growth rate was assumed to equal energy demand growth rate. Energy growth rate is based on total system annual energy forecasts excluding DSM.

- New Mexico Source: PNM 2007 Electric Resource Plan, page 14-15. New Mexico data was available from 2008 to 2016.

- Northern Nevada Source: Sierra Pacific Power 2007 IRP, excluding DSM.

- Northwest (Oregon, Washington and Northern Idaho) Source: Energy demand data from the Pacific Northwest Power and Conservation Plan, 2005. Peak demand growth rate was assumed to equal energy demand growth rate.

- Utah and Southern Idaho Source: Energy and peak demand load forecasts from IdahoPower's 2006 IRP and PacifiCorp's 2007 IRP were combined to create an estimate of demand growth in Utah and Southern Idaho.

- Wyoming Source: PacificCorp's 2007 Integrated Resource Plan. Data was available for 2006-2016; growth to 2020 was calculated based on the average annual growth rate between 2014 and 2016. Load in the rest of Wyoming, calculated from the EIA 2005 Electric Sales, Revenue and Price report, was assumed to increase at 2 percent per year. The PacificCorp load was combined with the rest of Wyoming load to create the final growth rates, calculated as the annual average growth rate between the computed statewide 2008 forecast and the 2020 forecast.

3. Alternative Data Sources – Comparison

We compared the Western region load growth forecasts against the Western states "transmission area" load forecasts used in the CEC "Scenario Analysis of California's Electricity System," (referred to here as the CEC Scenarios analysis). The CEC Scenarios analysis forecasts match relatively well with the Western States utility resource plans. The tables below present the comparisons between the Western States utility resource plan growth rates and the CEC Scenarios analysis.

Table 5. Comparison of Energy and Capacity Growth Rates in the Western Regions and the CEC Scenarios Transareas (Annual Average Growth Rate, 2008-2020)

Energy Demand Growth Rate			Peak Demand Growth Rate		
Western Region	Western State IOU Resource Plans (2008 - 2020)*	CEC Scenarios (2009 - 2020)	Western Region	Western State IOU Resource Plans (2008 - 2020)*	CEC Scenarios (2009 - 2020)
AB	1.9%	2.0%	AB	1.9%	1.9%
AZ	2.9%	2.8%	AZ	2.5%	2.8%
BC	1.4%	1.5%	BC	1.2%	1.2%
CFE	4.7%	4.7%	CFE	4.3%	4.3%
CO	2.0%	2.0%	CO	2.2%	2.0%
MT	1.3%	2.0%	MT	1.3%	2.0%
NM	2.1%	2.8%	NM	2.3%	2.8%
NV	1.8%	2.9%	NV	1.9%	2.9%
NW	1.4%	1.5%	NW	1.4%	1.4%
UT	2.0%	2.5%	UT	2.5%	2.7%
WY	3.1%	2.2%	WY	2.8%	2.1%

* Not all integrated resource plans cover the years 2008 - 2020. See the documentation of data sources.

This comparison required mapping the different areas used in those analyses to the eleven WECC regions outside of California used in this study. This mapping process did not always result in a perfect match between regions in the two studies. However, the WECC totals line up relatively well in both energy and capacity terms, indicating that differences between the two studies are largely due to mapping assumptions. The mapping between Western regions, SSG-WI zones and the CEC Scenarios transareas is summarized in the table below.

Table 6. Mapping of Western Regions to SSG-WI areas and to CEC Scenarios Transareas

Western Region	SSG-WI Area	CEC Scenarios Transarea Description
AB	ALBERTA	Alberta - South Alberta - Central-North
AZ	ARIZONA NEVADA WAPA L.C	Arizona Southern Nevada Palo Verde
BC	B.C.HYDR	British Columbia
CA	CEC areas applied to CA (see CEC mapping table)	CAISO Northern California CAISO - Southern California Edison CAISO - San Diego Gas & Electric CAISO - Zone Path 26 PG&E South Imperial Irrigation District Imperial Valley Los Angeles Department of Water and Power Miguel - East of San Diego San Francisco La Rosita Sacramento Utility District
CO	COL E COL W	Colorado - East Colorado - West
MT	MONTANA	Montana - Northwest Energy
NM	NEW MEXI	New Mexico
NV	SIERRA	Northern Nevada - Sierra Pacific Power
NW	NW_EAST NW_WEST	Puget Sound California - Oregon Border Transmission Hub
UT	IDAHO IPP KGB UT N UT S	Utah Idaho Power East - Wyoming South West Idaho Power West
WY	B HILL BHB BONZ JB LRS SW WYO WYO YLW TL	Wyoming Central East
CFE	MEXICO-C	Northern Baja California - CFE

1. Discussion

c. California

To extrapolate an energy growth rate from 2018 to 2020, energy demand was increased at a constant rate from 2018 to 2020, based on the average annual growth rate between 2015 and 2018. To find a peak demand forecast for the seven LSEs, some approximation was necessary. We used the CEC's estimate of 1-in-2 electric peak demand by control area for

2008 and 2018. The peak demand forecasts for each LSE therefore represent the sum of the coincident peak demands in each control area in the LSE region, rather than the coincident peak demand for the entire LSE region. The result is that our model will add capacity resources to meet coincident peak loads in each control area. To derive 2020 peak demand we again projected a constant growth in demand from 2018 based on the average growth rate between 2015 and 2018.

The CEC demand forecasts seek to account for the CPUC's energy efficiency rulemaking for EE targets through 2008. Energy efficiency savings from currently existing building standards and appliance codes are also incorporated into the CEC's demand forecast. However, the CEC writes that isolating the impacts of EE program is complicated by the fact that, "as models are calibrated to historic actual data, they implicitly account for the effects of many years of energy efficiency programs." Therefore, "users of the forecast can assume it includes a minimum level of future impacts consistent with 'business-as-usual' program mix and delivery." Our GHG analysis is consistent with the CEC's appraisal of EE in the load forecast. See the write-up on energy efficiency for more details.

No demand response impacts are included on the demand side of the CEC's forecasts because currently all demand response programs have some element of being dispatchable – only nondispatchable programs should be included in the demand forecast. The forecast does account for self-generation impacts on demand: the SGIP, CSI, New Solar Home Partnership and the Emerging Renewable Program are all included.

d. Rest of Western Region – Eleven Zones

For the rest of the Western regions, energy and peak demand growth rates between 2008 and 2020 were based on data from investor owned utilities' resource plans. While IOUs' resource plans do not cover a comprehensive and continuous territory for each of the regions, the resource plans provide a documented and publicly available source of load forecasts for service areas that cover the majority of load in each region, unlike the proprietary estimates from other models.

12. Energy Efficiency Methodology in the Greenhouse Gas Model

1. Energy Efficiency: Importance for Greenhouse Gas Model

Energy efficiency (EE) is an important resource for reducing greenhouse gas (GHG) emissions from the energy (electricity and natural gas) sector. Energy efficiency is particularly important because of its cost-effectiveness and the lack of commercially available greenhouse gas "scrubber" technologies. In a recent California Energy Commission (CEC) report that compared various energy efficiency, rooftop solar photovoltaic, and supply−side generating technologies – energy efficiency was determined to be "….by far the cheapest" resource.[15] In addition, California's *Energy Action Plan II* states that, "energy efficiency is the least cost, most reliable, and most environmentally-sensitive resource, and minimizes our contribution to climate change."[16]

In California, the CPUC and both investor- and publicly-owned utilities have pursued ambitious EE policies for many years and have committed to meeting additional efficiency goals over the next several years. In addition, utilities may soon ramp up EE efforts even further in order to meet the 2020 greenhouse gas emissions target.

Thus, since EE is seen as a cost-effective and available resource, it is crucial that the greenhouse gas model contain the best available estimate of EE potential and cost.

2. Approach to Modeling Energy Efficiency Scenarios

The E3 greenhouse gas calculator produces three primary outputs for a 2020 scenario: energy consumption, cost of energy consumption (e.g. energy rates), and GHG emissions. Users of the GHG calculator will be able to vary energy efficiency assumptions for the LSEs, among other inputs, to create their own scenarios which can be compared against two reference cases as well as alternative scenarios. [17] In the model, EE is subtracted from the load growth forecasts: as EE increases, the amount of new generation required in 2020 to meet electricity demand is reduced.

E3 proposes to model two 2020 reference cases against which other scenarios can be compared. The first 2020 reference case will reflect 'business-as-usual' in California and the rest of the Western region. The second reference case will reflect a more aggressive energy efficiency and renewable energy policy scenario in California. We expect that neither of these reference cases will result in a level of greenhouse gas emissions in 2020 that is equal to the electricity sector's GHG emissions in 1990.[18] Thus, target cases will also be modeled, by adding additional renewable energy to the aggressive policy reference case, until GHG

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[15] "Scenario Analysis of California's Electricity System: Preliminary Results For the 2007 Integrated Energy Policy Report," CEC, CEC-200-2007-010-SD, June 2007.

[16] CPUC and Energy Commission, *Energy Action Plan II*, adopted in 2005, available at http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

[17] The seven LSEs used in the electricity sector portion of GHG model are: PG&E, SCE, SDG&E, SMUD, LADWP, Northern Other publicly-owned utilities, Southern Other publicly-owned utilities. In the natural gas sector, we will model natural gas efficiency supply curves for PG&E, SCE and SoCalGas.

[18] Assembly Bill 32, the Global Warming Solutions Act, sets a statewide limit on greenhouse gas emissions equal to 1990 GHG levels by the year 2020. However, the law did not specify what portion of that GHG target must be met by the electricity sector.

emissions reach the electricity sector's 1990 level, as reported by the CEC's GHG emissions inventory.

Energy efficiency in the 'business-as-usual' reference case scenario is assumed to be included in the CEC load growth forecasts, so no additional load is netted out of the forecast in this case.[19] In the 'aggressive policy' reference case, EE is netted out of the growth forecast for each LSE, equivalent to 100 percent of the LSE's net economic potential (or 70 percent of the *gross* economic potential, assuming a net-to-gross ratio of 0.7) minus the LSE's current market potential. For the whole state of California, the aggressive policy reference case is equivalent to removing approximately 26,000 GWh of load from the 2020 load forecast and 5,600 MW from the 2020 load forecast. The EE assumptions for each case are described in detail in Section 2.b. Table 7 below shows the impact on California's load of these two reference cases.

Table 7. Impact of Energy Efficiency Scenarios and CSI on California Energy (GWh) Load Growth[20]

California Energy Demand Growth	Annual Avgerage Growth Rate of GWh (2008 - 2020)	Annual Average Growth Rate of MW (2008 - 2020)
Business-as-Usual Reference Case	1.2%	1.3%
Aggressive Policy Reference Case	0.5%	0.7%

The business-as-usual case and aggressive policy case will set the reference point against which other scenarios can be compared. Users of the GHG calculator will be able to vary the amount of EE achievement assumed for each LSE, in order to create their own scenario. This user-defined capability of the model relies on EE supply curves to create a continuous relationship between EE savings and cost. EE measures are each associated with a price ($/kwh or $/therm) and a market potential supply (MWh or therm savings): these two components create the supply curve.

The GHG model will contain supply curves representing economic energy efficiency potential for each LSE. Users of the GHG calculator will be able to specify what percentage of the cost effective portion of the supply curve will be obtained by each LSE in 2020.

a. Methodology to Create Supply Curves and EE Reference Cases

Table 8 below summarizes the approach used to obtain the levels of energy efficiency assumed in the two reference cases. The methodology used to extend the energy efficiency potential data from 2016 to 2020 is also described below, along with a more detailed explanation of how the savings estimates for each LSE were achieved.

Table 8. Approach used to establish electricity EE savings estimates for the LSEs in 2020

EE Savings in 2020	Business-as-Usual	Aggressive Policy
Reference Case	Business-as-usual energy efficiency included in the CEC load growth forecast, no additional EE is subtracted from the load. We assume 100% of current market potential is achieved in the business-as-usual reference case.	100% of net economic potential in 2020 (extrapoliation of targets to 2020 is equal to the growth rate of economic potential between 2008 - 2016, assume NTG of 0.7)

[19] Source of the current policy base case load forecast: "California Energy Demand 2008-2018 Staff Revised Forecast," CEC-200-2007-015-SF, October 2007.

[20] See the California Solar Initiative (CSI) methodology write-up for details of the impact of CSI on the load growth forecasts.

For the natural gas sector, the energy efficiency assumptions in the aggressive policy reference case are below 100% of economic potential.

The following steps outline the methodology used to obtain the GWh and MW savings numbers used in the two reference cases described in Table 8 above:

1. Creating the supply curves:
    a. The data underlying the supply curves is derived from the SMUD and investor-owned utilities (IOU) 2006 energy efficiency potential studies created by the consulting firm Itron. Both studies contain data on efficiency measures in the residential and commercial sectors. The IOU study also contains data on the industrial sector. From this data we created two EE supply curves for each IOU and for SMUD: one reflecting economic potential and the other reflecting market potential. Economic potential is the set of all cost effective energy efficiency measures. Market potential is a subset of economic potential: it only includes the measures which are likely to be adopted by people given market barriers and the current level of utility rebates. In the supply curves, cumulative MWs saved falls along the x-axis, and utility spending per MWh saved falls along the y-axis.
    b. **Supply Curves for the IOUs:** Create electricity EE supply curves for the three electricity IOUs by combining data on measures for residential and commercial (new and existing) buildings, and new industrial buildings. Create natural gas EE supply curves for PG&E, SDG&E and Southern California Gas (SoCalGas) by using available data on natural gas energy efficiency measures. Natural gas supply curves reflect the SoCalGas energy efficiency measures, which are scaled to reflect economic potential in the other natural gas service territories.
    c. **Supply Curves for SMUD:** Create electricity sector supply curves by combining data from the 2006 "SMUD Energy Efficiency Potential Study" on existing residential and existing commercial measures.
    d. **Supply Curves for LADWP and the other Publicly-Owned Utilities (POUs):** In some cases, E3 did not have access to the measure-by-measure energy efficiency potential data for public utilities. In the case of LADWP, this information was not readily available. For the other POUs, there are individual measure by measure supply curves for each utility, but the effort required to reach agreement to disclose this information with each utility and then aggregate across 40 utilities was not feasible in the timeframe or with available resources. Therefore, we have created approximate supply curves for LADWP, the Northern California POUs, and the Southern California POUs. To create approximate EE supply curves for these utilities, we began by using the 2008 and 2016 economic potential data reported for the POUs in the CEC's AB2021 report, "Statewide Energy Efficiency Potential Estimates and Targets for California Utilities," released in August 2007. Economic potential for the 'Northern other' municipal utilities and the 'Southern other' municipal districts was summed together, creating a Northern and Southern POU estimate for total economic potential in 2008 and 2016. Economic potential data for LADWP was only available for 2016, so their 2008 economic potential was extrapolated based on an assumption that LADWP's

economic potential growth rate mirrors that of the average of the other municipally owned utilities. These numbers were then adjusted to approximate the cumulative economic EE potential available from 2008 – 2020, by assuming linear growth of economic potential.

The 2008 and extrapolated 2020 economic potential numbers for the Northern and Southern POUs were then used in the calculation to create the supply curves for these two groups of utilities. E3 used the SCE EE supply curve, scaled to meet the economic potential targets for LADWP and the "Southern Other POUs." We likewise used the PG&E supply curve, scaled to meet an appropriate supply curve for "Northern Other POUs." Both of these scaling operations were based on the ratio between the POUs economic potential in 2008 and 2020, compared to the economic potential of their closest IOU neighbor. Since few California POUs operate a natural gas distribution system, E3 does not plan on creating natural gas EE supply curves for the POUs.

2. Netting out current market potential from economic potential:

    a. Current market potential energy efficiency measures are included as a subset of the economic potential data. To avoid double counting this EE, in both the business-as-usual reference case and the aggressive policy reference case, it was necessary to net out forecasted current market potential through 2020 from the cumulative economic potential numbers.

    b. To generate extrapolate the supply curves from 2016 to 2020, we assumed that energy efficiency potential available for each year between 2016 and 2020 would continue to grow at the same average rate that EE potential grew between 2008 and 2016.

3. Determining the appropriate energy efficiency savings level for each IOU for the current policy base case and the aggressive policy base case:

    a. The CPUC and Energy Commission only allow utilities to earn credit for EE savings that are the direct result of utility EE programs, and which would not have happened anyway, in the absence of the program. These are "net" savings, EE savings net of all savings which were not the direct result of a utility program. The CPUC has currently set EE targets for the IOUs through 2013, and the CEC has set targets for the POUs through 2016. Thus, to extrapolate these targets to 2020 and estimate the level of energy efficiency that the utilities might achieve in 2020 required some estimation. We assumed that an aggressive EE target for the utilities in 2020 would be to achieve 100 percent of net economic potential. Assuming a net-to-gross ratio of 0.7, this is equivalent to 70 percent of gross economic potential. This target, achieving all cost effective economic potential in 2020, is a stretch goal. This is the level we chose to use for the aggressive policy reference case. See Appendix A for a graphical comparison of utility EE targets compared to economic and market potential.

4. Estimate Costs for Energy Efficiency

    a. The costs for the energy efficiency are broken into two categories; (1) incentives and direct install costs, and (2) administration, marketing, and measurement and evaluation (M&E) costs. The incentive and direct install costs are computed as a user defined percentage of the total resource cost (TRC) costs. An analysis of existing utility programs shows the existing level of incentives averages about 50% of the TRC cost. For higher levels of EE penetration (e.g. utilities achieve 100% of economic potential), we are assuming incentives increase as a percentage of the TRC cost. Since there is no existing data on historical costs to achieve these increased levels of energy efficiency, we assume that incentives equal to 100% of TRC costs would be necessary to achieve 100% of economic potential.

b. For administration, marketing, and M&E costs, we have modeled these as a percentage of the incentive costs. With this approach, these costs increase as programs get larger. The current utility programs have administration, marketing, and M&E costs at approximately the same level as incentives and direct install costs. Therefore, the default assumption for all cases is that these costs equal the incentive costs.

c. The Net to Gross ratio is also important to costs, since we are computing costs per incremental savings attributable to the program. The assumption in the base case analysis is to assume a 0.7 Net to Gross ratio. This assumption can be changed in the analysis tool. Resulting costs are shown in Appendix B for 75% Economic Potential and 100% Economic Potential.

It is important to note that while these energy efficiency scenarios resulted from consultation with EE goals, projections, standards and regulations, the final choice of EE levels, and the creation of the EE supply curves for use in the model requires estimation and interpretation. This is due to an overall lack of consistent data designed for the purposes of forecasting future EE scenarios, uncertainty with respect to new construction and appliance "volumes," net versus gross savings projections, what level of efficiency is included in the CEC load growth projections, and the costs associated with achieving energy savings.

The tables below summarize the load growth forecasts for the seven LSEs in California for the business-as-usual reference case and the aggressive policy reference case, once energy efficiency from each scenario has been netted out.

Table 9. Business-as-Usual Reference, California Load Forecast, 2008 – 2020 [21]

Business-as-Usual Reference Case						
Source: CEC Staff Final Energy Demand Forecast Report, October 2007						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	21,886	1.3%	81,532	95,598	1.3%
SCE	21,476	25,777	1.5%	87,966	106,018	1.6%
SDG&E	3,712	4,423	1.5%	18,687	22,651	1.6%
SMUD	3,174	3,741	1.4%	11,887	13,990	1.4%
LADWP	5,717	6,010	0.4%	28,004	29,592	0.5%
NorCalMunis	5,077	5,942	1.3%	35,720	39,440	0.8%
SoCalMunis	5,079	5,959	1.3%	35,148	38,276	0.7%
California	62,946	73,738	1.3%	298,945	345,566	1.2%

[21] The CEC load forecasts project through 2018. To get to 2020, the loads were increased at the rate of growth of the load between 2015 and 2018. See the methodology write-up on load forecasts for more details about the mapping of CEC regions to this study's seven LSEs.

Table 10. Aggressive Policy Reference Case, California Load Forecast, 2008 – 2020

Aggressive Policy Reference Case						
Resource Zone Name	2008 Peak (MW)	2020 Peak (MW)	Annual Avg. Growth in Peak 2008-2020 (%)	2008 Load (GWh)	2020 Load (GWh)	Avg. Annual Growth in Load 2008-2020 (%)
PG&E	18,711	19,900	0.5%	81,532	85,716	0.4%
SCE	21,476	23,799	0.9%	87,966	97,194	0.8%
SDG&E	3,712	4,096	0.8%	18,687	20,904	0.9%
SMUD	3,174	3,551	0.9%	11,887	12,686	0.5%
LADWP	5,717	5,504	-0.3%	28,004	27,223	-0.2%
NorCalMunis	5,077	5,654	0.9%	35,720	38,397	0.6%
SoCalMunis	5,079	5,599	0.8%	35,148	36,980	0.4%
California	62,946	68,102	0.7%	298,945	319,100	0.5%

3. Alternative Approaches

Using supply curves as the analytical model to estimate EE costs and savings is not the only possible approach. As an alternative, one could attempt to simulate the costs and energy savings from a variety of packages of EE programs, building standards and codes which would not be placed on the hierarchy of a supply curve. Then, rather than moving up or down an EE supply curve, the user of the GHG calculator would select from a range of pre-determined EE programs. This approach would avoid some of the analytical pitfalls of EE supply curves, and might better simulate the on-the-ground reality of EE programs as currently administered by utilities. However, to create realistic packages of EE programs and costs for each LSE in 2020 would require compiling a great deal of data, the scope of which is beyond this project. In addition, the accuracy of the EE savings and cost estimates for these hypothetical EE "programs" would not necessarily be more accurate or precise than the current method of using EE supply curves and would leave the GHG calculator with less flexibility to model different EE levels.

Although the energy efficiency supply curve approach holds some inherent limitations, as discussed below, we believe that the "supply curve" approach is the most flexible, transparent and realistic method for incorporating energy efficiency into the resource supply build-out in 2020.

4. Discussion

The analysis of energy efficiency potential in 2020 used in this model relies on the best, currently available data.[22] Even the best currently available data is subject to some caveats, and adapting this data to our model introduces additional caveats. This section presents some of the caveats and limitations to the EE methodology applied in the GHG calculator.

- *Supply curves simplify reality:* [23] Energy efficiency, as a resource, consists of many heterogeneous groups of technologies and programs, making it a difficult resource to quantify accurately in a uniform dataset. In addition, there are a number of market

[22] The Itron 2006 EE potential studies are currently under revision, and this new data will be incorporated into our analysis as soon as it is publicly available.

[23] For a more detailed discussion of the limitations of energy efficiency supply curves see: Rufo, Mike, "Developing Greenhouse Gas Mitigation Supply Curves for In-State Resources," PIER Consultant Report P500-03-025FAV, April 2003.

barriers to the adoption of energy efficiency which often prevent consumers from making least-cost purchasing choices. An energy efficiency supply curve is a simplification of the impacts of a range of policies, and does not necessarily reflect the choices of individuals or energy efficiency program administrators. In reality, EE programs may not always be implemented in order of cost effectiveness.

- *Energy efficiency embedded in the load forecast and the natural rate of EE are hard to quantify*: To the extent possible, we have attempted to explicitly account for the amount of energy efficiency embedded in the load forecasts and the amount of energy efficiency built into each of the two reference cases. The CEC's staff revised forecast of California energy demand (2008-2016) contains a description of the EE assumptions applied in their load growth forecasting model. The CEC reports that, "Building and appliance standards are modeled within the residential and commercial forecast models…In addition, as models are calibrated to historic actual data, they implicitly account for the effects of many years of energy efficiency programs." Historic data will also reflect energy efficiency improvements which would have likely occurred even in the absence of energy efficiency programs, due to the improvement of technology over time. It is difficult to quantify what level of "natural" energy efficiency improvements is included in the CEC load growth forecasts.

- *The mix of available EE measures will change in the future in unpredictable ways:* Any forecast of the future is by definition uncertain; however there are particular uncertainties associated with the energy efficiency projections that are worth highlighting. In creating an energy efficiency supply curve for 2020, we relied on data that was extrapolated from current economic conditions for avoided costs, technology costs, retail rates, etc. If avoided costs turn out to be higher than projected in 2020, for example, a larger set of energy efficiency measures would become economically feasible. Each data point contains a set of embedded assumptions; the nuances of which can be lost when the data is lumped together into a single supply curve.

  In addition, less research has been put into the development of the "high-end" of the energy efficiency supply curve, namely the measures and technologies which are not currently considered to be economic or effective. However, some of the very high energy efficiency policy scenarios begin to rely on this higher end of the supply curve, where actual costs are less reliable.

- *Adoption rates of EE may change in the future under different program administration paradigms:* In California, energy efficiency programs are currently administered through utilities – a reality which partially defines the scope of energy efficiency measures that are feasible. This analysis was not able to capture the potential for new energy efficiency rollout mechanisms such as the proposal for market trading of "energy savings certificates" or establishing statewide programs and appointing a statewide program administrator. Likewise, this analysis did not account for the possibility of a "sea-change" in public attitudes and behavior towards energy efficiency, which may result in more aggressive adoption rates for energy efficiency. It is currently unknown what might bring about such a sea-change in the public's attitudes and behaviors towards EE, but some possibilities include heightened public awareness of climate change or energy shortages, or more effective advertisement of EE programs.

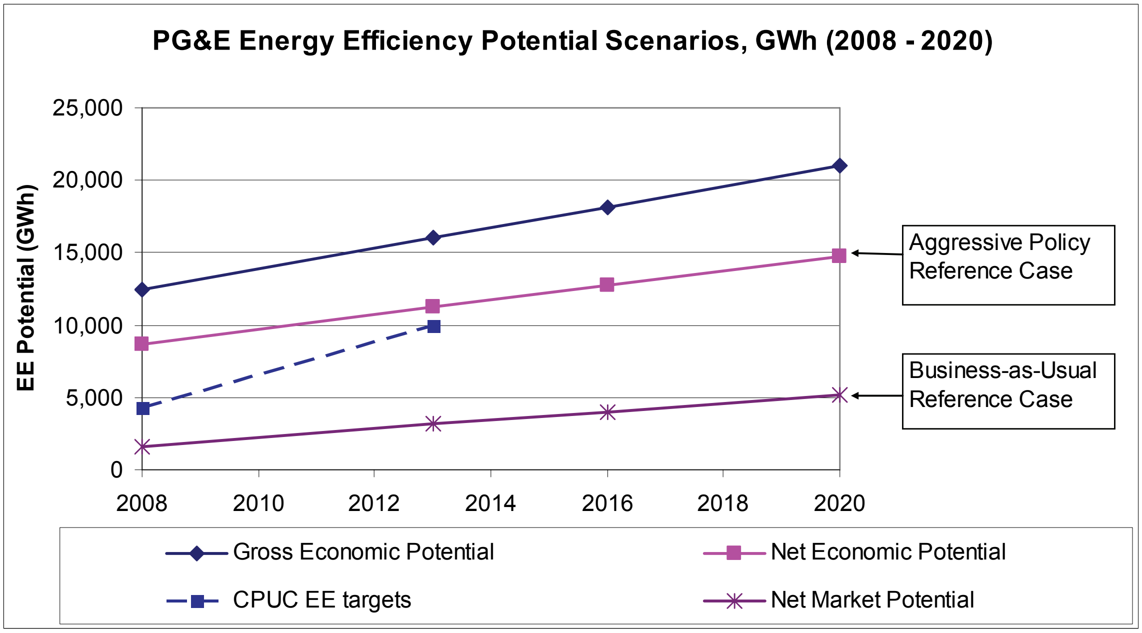
5. Sources Consulted

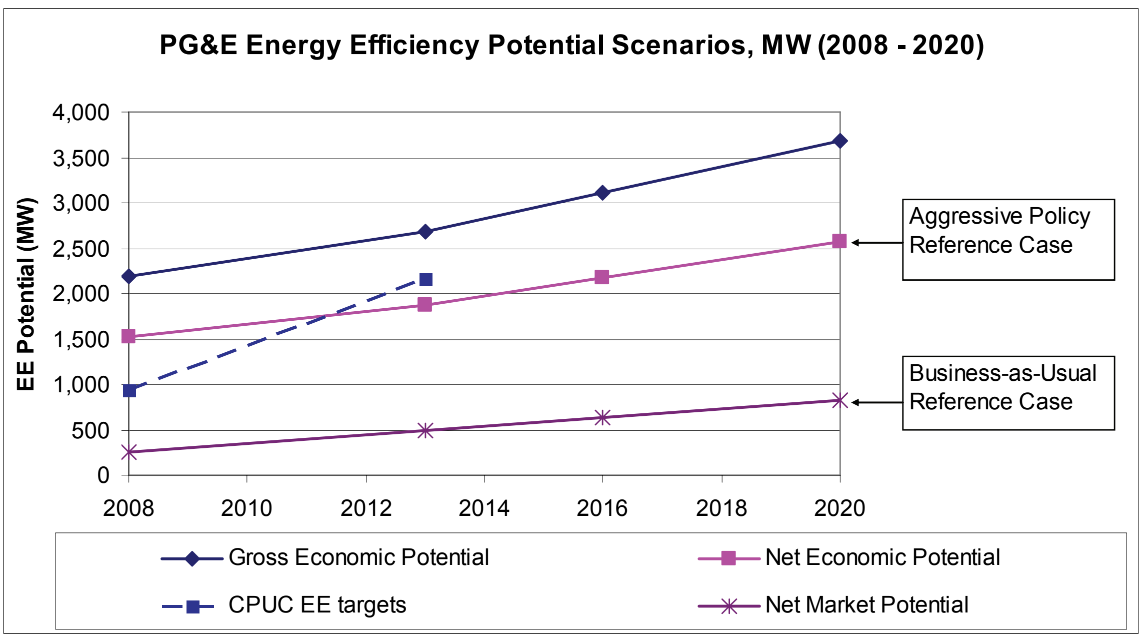
The table below summarizes the recent Energy Commission, Public Utility Commission and utility sponsored analyses of future energy efficiency scenarios.

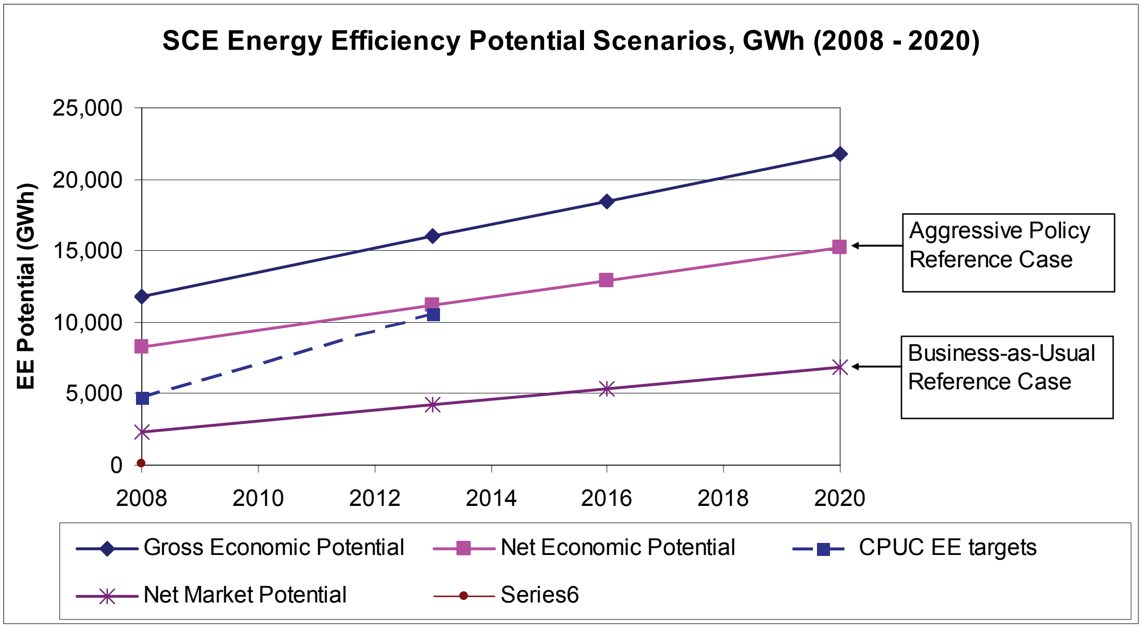
	California Energy Efficiency Report	Year	Years Covered	Sectors Studied	Area / LSEs Studied
a)	*CEC Draft Staff Report: Statewide Energy Efficiency Potential Estimates and Targets for California Utilities*	2007	2007 – 2016	Residential, Commercial, Industrial: Electric and Natural Gas	IOUs and POUs in CA
b)	*Interim Order on Issues Related to Future Savings Goals and Program Planning for 2009 – 2011 Energy Efficiency and Beyond [includes big, bold efficiency strategies (BBEES)]*	2007	2009 – 2011 and beyond	Residential and Commercial new construction, residential and small commercial HVAC	IOUs
c)	*Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond,* CPUC	2004	2004 – 2013	Electric and Natural Gas sectors	IOUs
d)	*Establishing Energy Efficiency Targets: A Public Power Response to AB2021*, CMUA (with RMI)	2007	2007 – 2016	Residential, Commercial, Industrial: Electric sector only	POUs: excluding SMUD, LADWP, CPAU, Redding, SVP
e)	*Scenario Analyses of California's Electricity System: Preliminary Results for the 2007 IEPR*, CEC	2007	2009 – 2020	Electric sector only	California state-level analysis

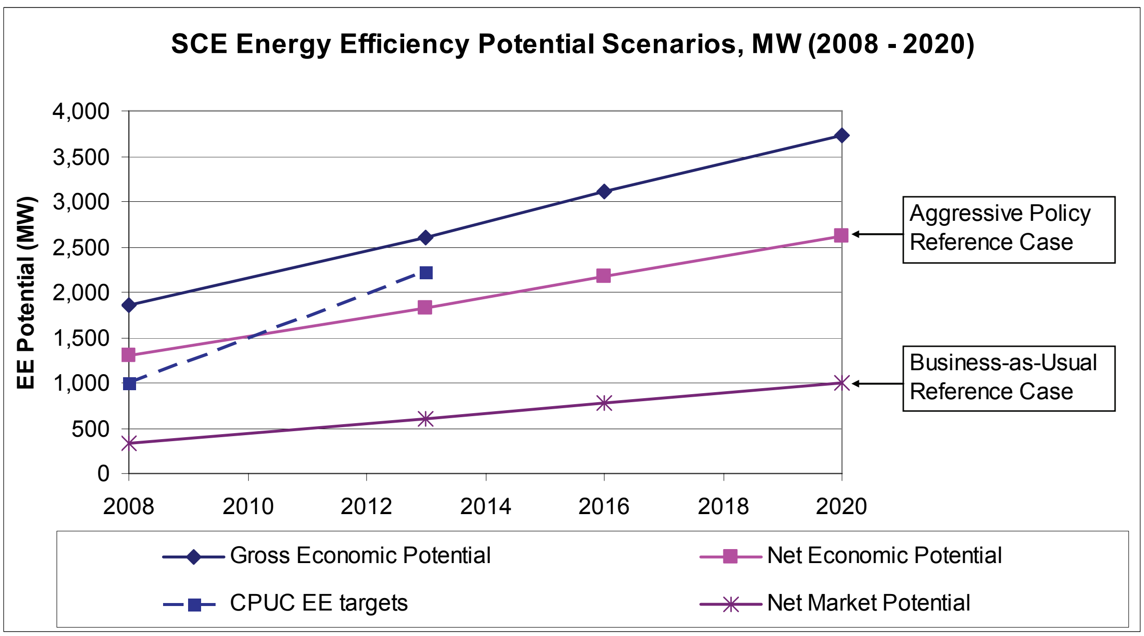
6. Appendix A

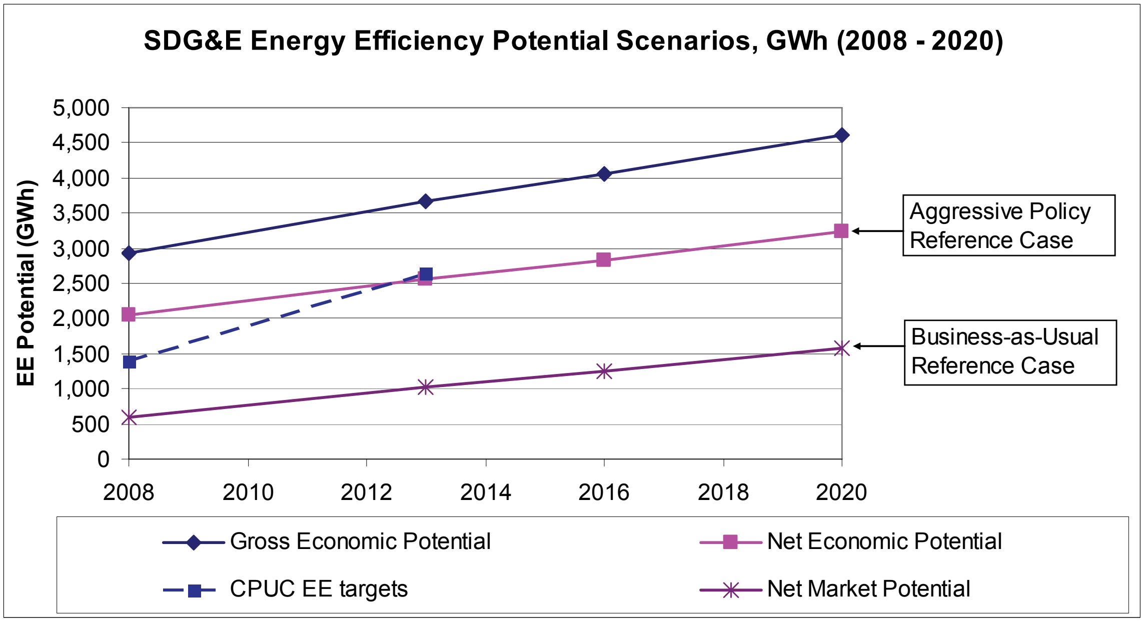
The following tables illustrate the differences between the energy efficiency scenarios used in this study for the seven LSEs and their respective energy efficiency goals.

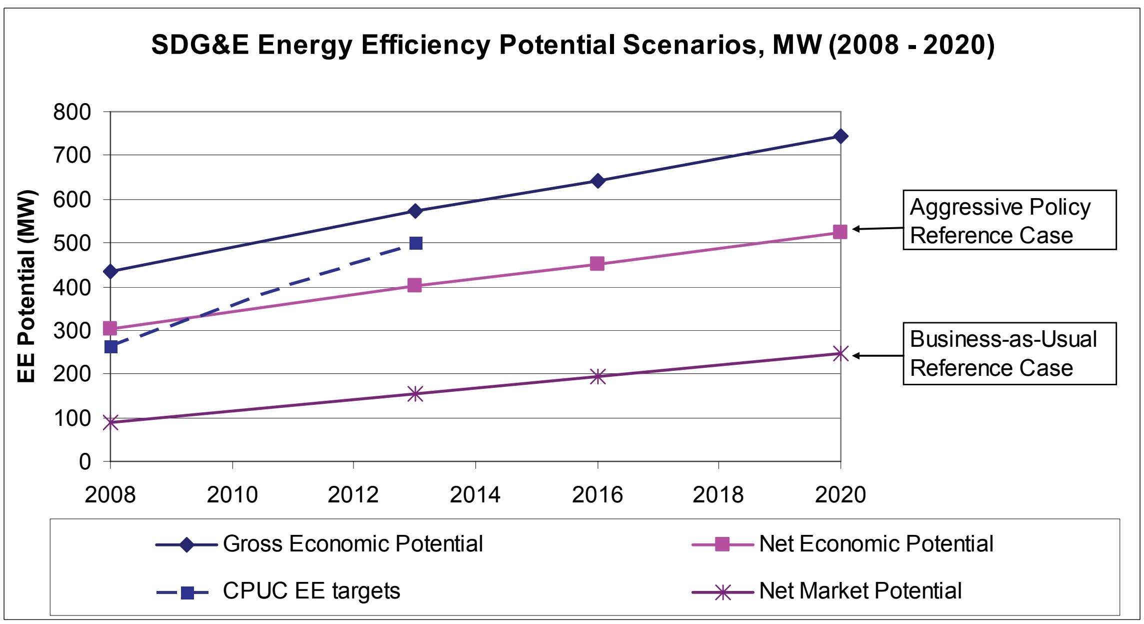


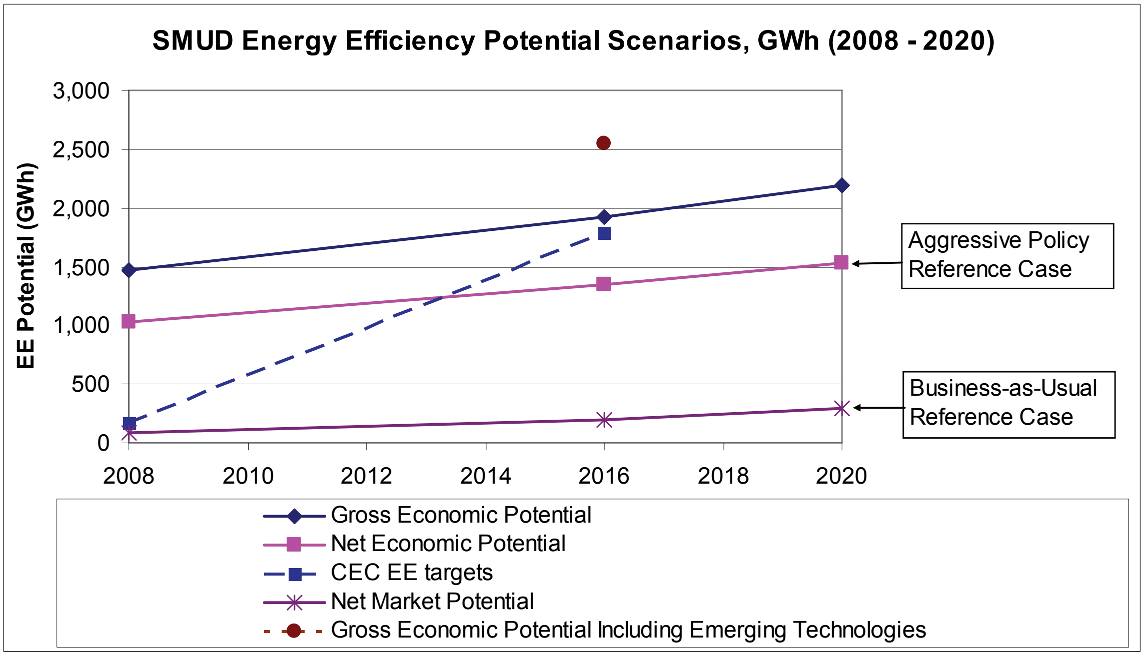



SCE Energy Efficiency Potential Scenarios, GWh (2008 - 2020)
EE Potential (GWh)
25,000
20,000
15,000
10,000
5,000
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CPUC EE targets
Net Market Potential
Series6

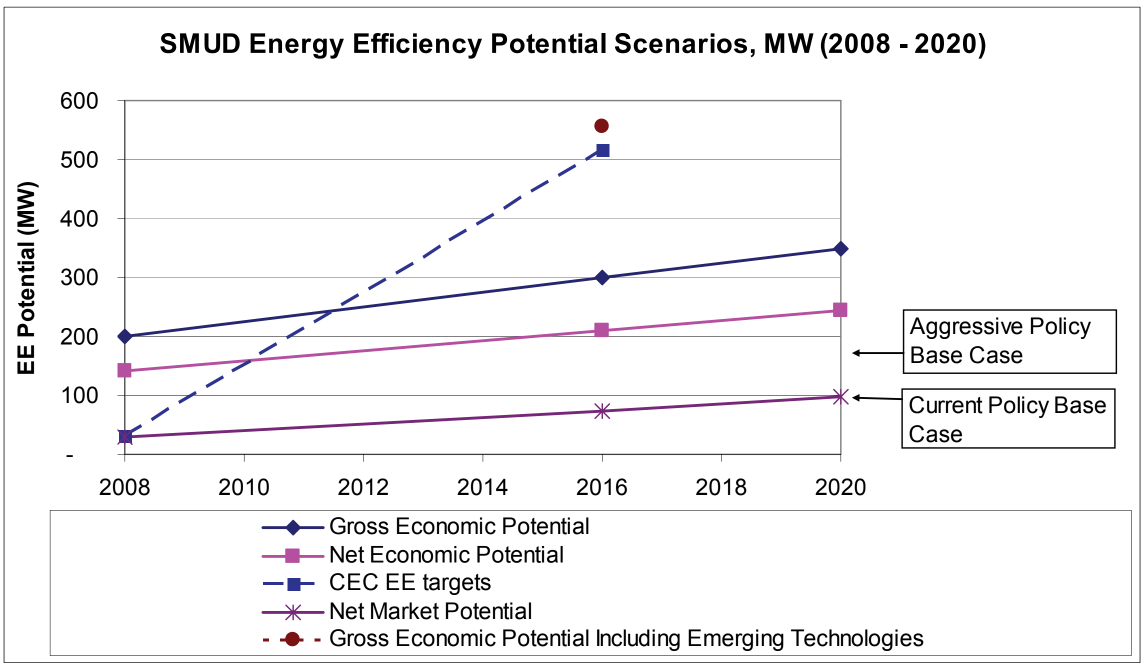

SCE Energy Efficiency Potential Scenarios, MW (2008 - 2020)
EE Potential (MW)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CPUC EE targets
Net Market Potential


SDG&E Energy Efficiency Potential Scenarios, GWh (2008 - 2020)
EE Potential (GWh)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CPUC EE targets
Net Market Potential

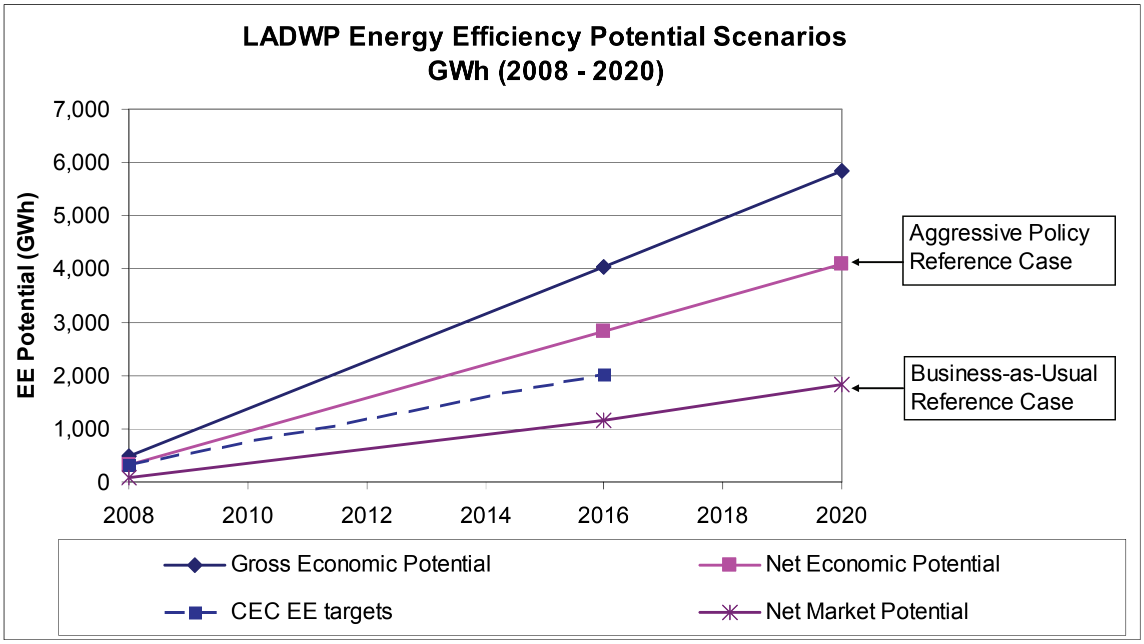

SDG&E Energy Efficiency Potential Scenarios, MW (2008 - 2020)
EE Potential (MW)
800
700
600
500
400
300
200
100
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CPUC EE targets
Net Market Potential

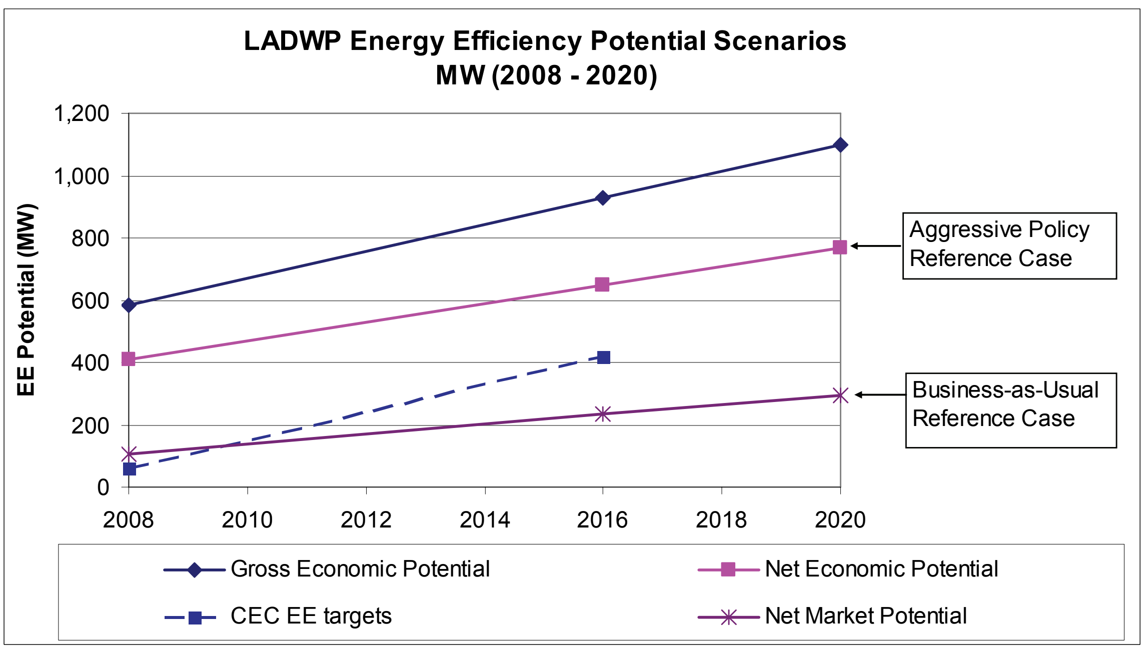


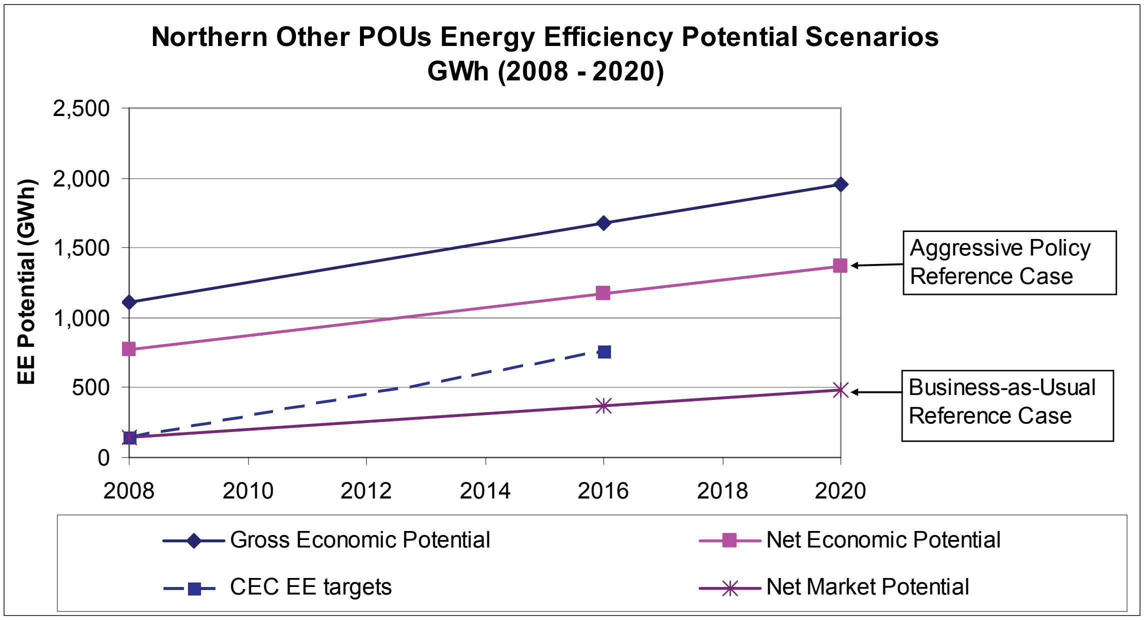
SMUD Energy Efficiency Potential Scenarios, GWh (2008 - 2020)
EE Potential (GWh)
3,000
2,500
2,000
1,500
1,000
500
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential
Gross Economic Potential Including Emerging Technologies



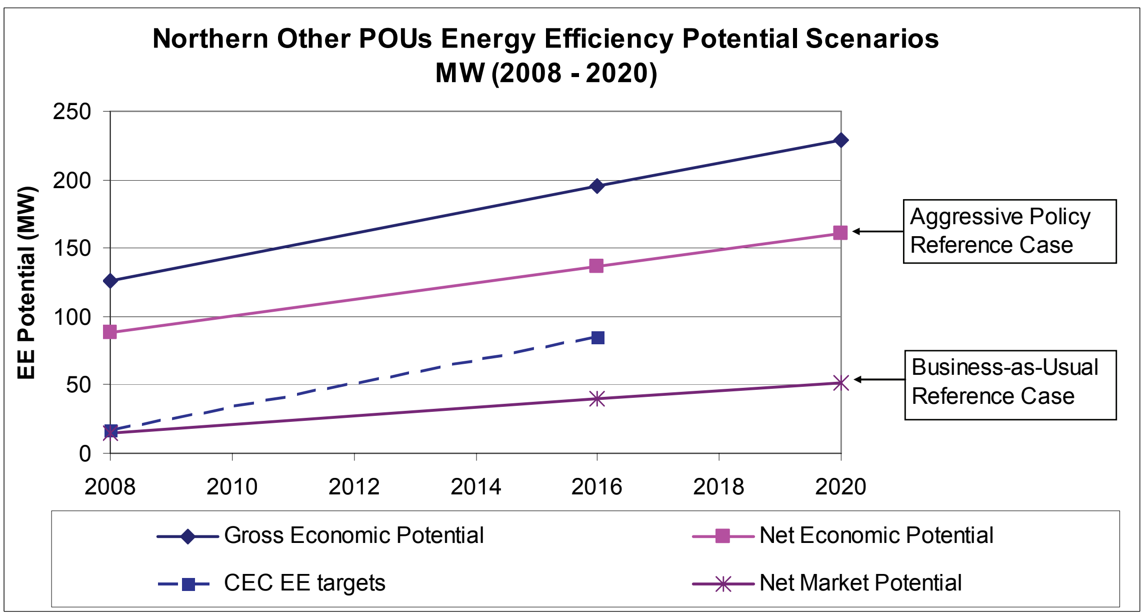
SMUD Energy Efficiency Potential Scenarios, MW (2008 - 2020)
EE Potential (MW)
600
500
400
300
200
100
-
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Base Case
Current Policy Base Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential
Gross Economic Potential Including Emerging Technologies


LADWP Energy Efficiency Potential Scenarios
GWh (2008 - 2020)
EE Potential (GWh)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential

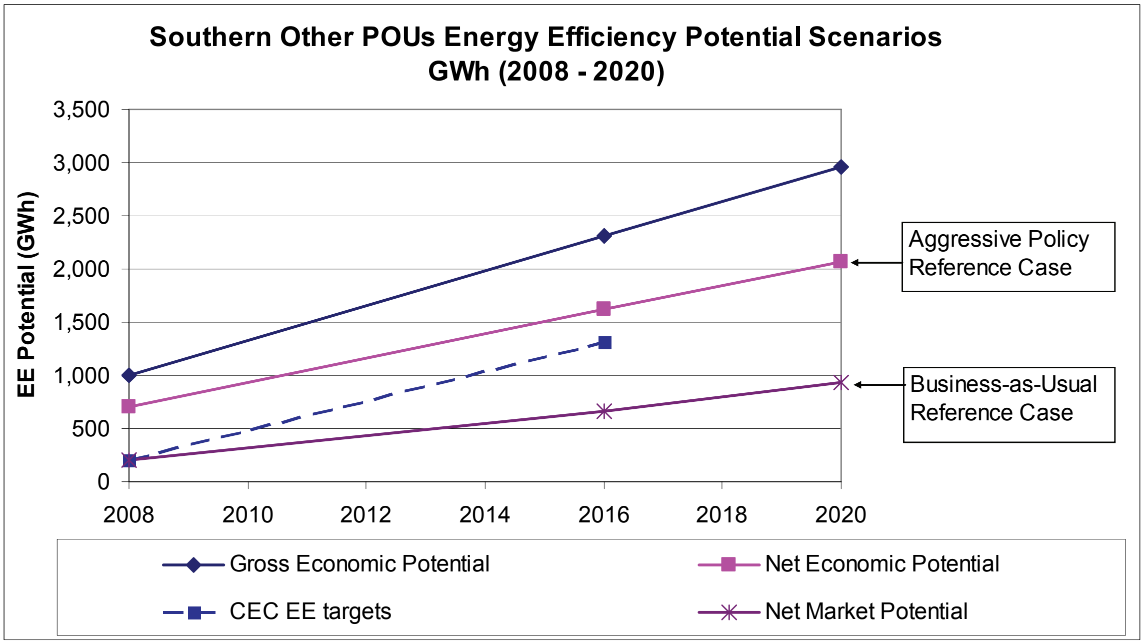

LADWP Energy Efficiency Potential Scenarios
MW (2008 - 2020)
EE Potential (MW)
1,200
1,000
800
600
400
200
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential

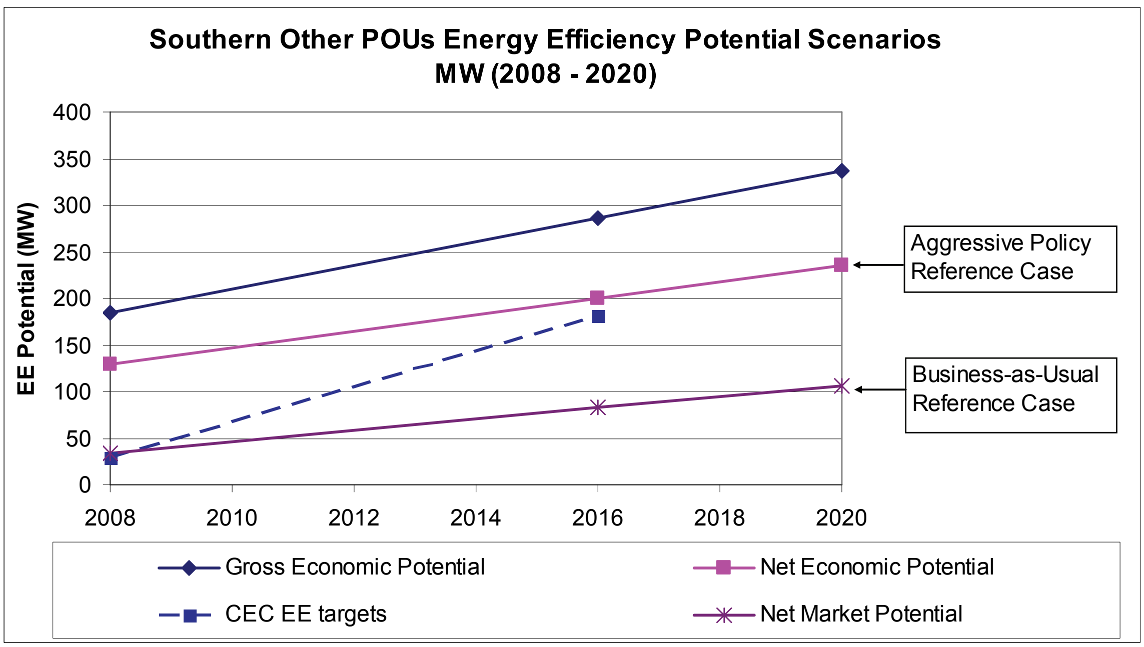


Northern Other POUs Energy Efficiency Potential Scenarios
GWh (2008 - 2020)
EE Potential (GWh)
2,500
2,000
1,500
1,000
500
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential



Northern Other POUs Energy Efficiency Potential Scenarios
MW (2008 - 2020)
EE Potential (MW)
250
200
150
100
50
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential


Southern Other POUs Energy Efficiency Potential Scenarios
GWh (2008 - 2020)
EE Potential (GWh)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential


Southern Other POUs Energy Efficiency Potential Scenarios
MW (2008 - 2020)
EE Potential (MW)
400
350
300
250
200
150
100
50
0
2008
2010
2012
2014
2016
2018
2020
Aggressive Policy Reference Case
Business-as-Usual Reference Case
Gross Economic Potential
Net Economic Potential
CEC EE targets
Net Market Potential

Appendix B:

Aggressive Policy Reference Case Results for 100% Economic Potential

Statewide EE Assumptions - Penetration, Savings in 2020

	Achievement % of Economic	EE Program Spending $M/Year	Net GWh Saved	Net MW Saved	Net Therms Saved	TRC Cost $/kWh
PG&E	100%	$ 1,533	14,718	2,572	74,731	$ 0.1041
SCE	100%	$ 1,323	15,240	2,712	17,982	$ 0.0868
SDG&E	100%	$ 289	3,230	517	3,948	$ 0.0894
SMUD	100%	$ 125	1,536	252	-	$ 0.0812
N. Cal POUs	100%	$ 143	1,371	240	6,962	$ 0.1041
LADWP	100%	$ 355	4,084	727	4,819	$ 0.0868
S. Cal POUs	100%	$ 180	2,074	369	2,447	$ 0.0868
California Totals		**$ 3,947**	42,253	7,388	110,888	$ 0.0934

Incremental Savings from CEC 2008 to 2018 Load Forecast for 100% Economic Potential

Incremental Savings to Load Forecast	Net GWh Saved	Net MW Saved	Net Therms Saved
PG&E	9,500	1,744	74,731
SCE	8,401	1,709	17,982
SDG&E	1,657	270	3,948
SMUD	1,248	155	-
N. Cal POUs	885	188	6,962
LADWP	2,251	431	4,819
S. Cal POUs	1,143	263	2,447
California Totals	25,086	4,761	110,888

Comparison: Energy Efficiency Results for 75% Economic Potential

	Achievement % of Economic	EE Program Spending $M/Year	Net GWh Saved	Net MW Saved	Net Therms Saved	TRC Cost $/kWh
PG&E	75%	$ 862	11,038	1,929	56,048	$ 0.0911
SCE	75%	$ 744	11,430	2,034	13,486	$ 0.0760
SDG&E	75%	$ 162	2,423	388	2,961	$ 0.0782
SMUD	75%	$ 70	1,152	189	-	$ 0.0711
N. Cal POUs	75%	$ 80	1,028	180	5,221	$ 0.0911
LADWP	75%	$ 199	3,063	545	3,614	$ 0.0760
S. Cal POUs	75%	$ 101	1,555	277	1,835	$ 0.0760
California Totals		**$ 2,220**	31,690	5,541	83,166	$ 0.0817

Incremental Savings from CEC 2008 to 2018 Load Forecast for 75% Economic Potential

Incremental Savings to Load Forecast	Net GWh Saved	Net MW Saved	Net Therms Saved
PG&E	5,821	1,101	56,048
SCE	4,591	1,031	13,486
SDG&E	849	141	2,961
SMUD	864	92	-
N. Cal POUs	542	128	5,221
LADWP	1,230	249	3,614
S. Cal POUs	625	171	1,835
California Totals	14,523	2,914	83,166

13. California Solar Initiative (CSI)

A. Overview

The California Solar Initiative (CSI) is California program to encourage installation, research, and market transformation of solar photovoltaic systems in California. The CSI program implements the Governor's Million Solar Roofs initiative, with a target of installing 3,000MW of solar in California.

B. Recommended value(s)

Two reference cases are developed, in the business-as-usual case solar continues to be installed at the current pace which results in a total of approximately 1,091MW based on estimates included in the CEC 2008-2018 Load Forecast. The aggressive policy reference case achieves the 3,000MW target in 2020. For the target case that achieves 1990 emissions levels we assume 3,000MW of solar is installed.

Since the reference case of approximately 1,091MW is already included in the CEC 2008-2018 load forecast used in the analysis, both the impact on peak load and energy are already accounted for in the load forecast. In the 3000MW case, an impact of an additional 1,909MW of PV is subtracted from the load forecast. We assume a capacity factor of 18% and a coincident peak load of 45.8% based on the CEC 2008-2018 forecasts to make this adjustment.

Two cases are similarly evaluated for the costs of PV, a reference case that does not assume any cost improvements over time (no market transformation) and has costs of $8 per watt in $2006 dollars. The no market transformation case is the same case assumption for all resources. In the market transformation case, the costs are assumed to improve to $4.60/W by 2016 in $/W.

C. Data sources

The following table shows the assumptions used to compute the CSI impacts on the State's load and energy requirements based on the revised 2008-2018 load forecast.

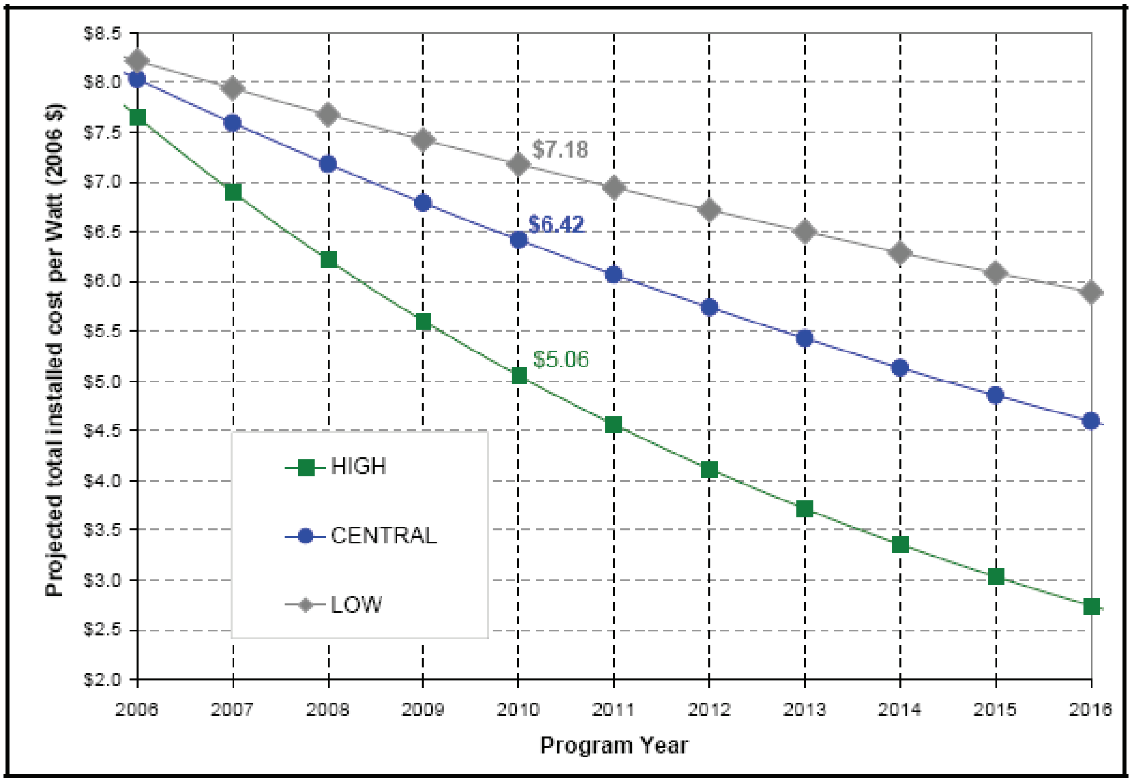
Assumptions on CSI

CEC Scenarios Analysis, Appendix E.2	
De-Rate Factor by Area - PV	
Summer Peak 12 PM-6 PM	
CNP15	48%
CSCE	45%
CSDG	42%
LADWP	46%
SMUD	48%
CZP26	46%
Simple Average of CA	46%
PV Capacity Factor	18%
CEC Revised Load Growth Forecast, Figure 11, pg. 31	
Forecast of Peak Impacts of CSI	
	MW
New PV Installations, 2018, coincident peak	500
New PV Installations, 2018, nameplate	1091
2020 PV Goal	3000
Additional PV nameplate needed to meet goal	1909
Peak Load Reduction of Additional PV	875
Energy Load Reduction of Addition PV (GWh)	1,380

The other component important to the costs of reducing CO2 emissions levels is the installed cost of CO2 systems. This is evaluated in two components, the incentive costs that are collected in retail rates, and the customer costs. Together the incentive cost plus the customer costs equal to the total cost of the system.

The following figure, from the 2007 CPUC Self-Generation Incentive Program report on Solar PV Costs and Incentive Factors Report forecasts total installed costs of PV systems. The 2006 costs in this study (most recent reviewed in the analysis) show approximately $8/W installed as the central estimate. This decreases to $4.60/W in $2006 by 2016. Therefore, significant market transformation is illustrated in the estimates.

Figure 4-14: Projected Changes in Total Installed Costs



To be consistent with the treatment of all other resources in the analysis, the conservative estimate of no market transformation is assumed in the reference cases. In the sensitivity planned that includes market transformation effects the costs of PV are assumed to follow the central estimate in the study.

The following table shows the costs used in each of these cases.

Assumptions of Average Installed Cost of PV Forecast

Costs in $2006 $/W Installed	No Market Transformation	With Market Transformation
2008	$ 8.00	$ 7.18
2016	$ 8.00	$ 4.60
2020*	$ 8.00	$ 4.60

Costs in Nominal $/W (Assuming 2.5% inflation)	No Market Transformation	With Market Transformation
2008	$ 8.41	$ 7.54
2016	$ 10.24	$ 5.89
2020	$ 11.30	$ 6.50

*Forecast from 2016 to 2020 is done to keep costs constant in real terms.
Source:
CPUC Self-Generation Incentive Program
Solar PV Costs and Incentive Factors
Prepared by ITRON
February, 2007

Of the total installed cost, the CSI incentive program is offsetting the costs. CSI is designed with 'steps' that decrease the incentive over time as more and more PV installations are made. The steps are defined in the program by utility and sector, residential, non-residential, and government.

The following two tables provide the resulting costs and impacts of the CSI program for the two reference cases.

Business As Usual Reference Case

CSI in the 2020 Forecast	GWh	Nameplate MW	Coinc MW	Utility Cost $2020 ($000)	Customer Cost $2020 ($000)
PG&E	752	477	218	$ 894	$ 2,702
SCE	789	500	229	$ 938	$ 2,837
SDG&E	180	114	52	$ 213	$ 645
SMUD	0	0	0	$ -	$ -
LADWP	0	0	0	$ -	$ -
NorCalMunis	0	0	0	$ -	$ -
SoCalMunis	0	0	0	$ -	$ -
Total	**1720.2888**	**1091**	**499.678**	**$ 2,045**	**$ 6,185**

Aggressive Policy Reference Case

CSI in the 2020 Forecast	GWh	Nameplate MW	Coinc MW	Utility Cost $2020 ($000)	Customer Cost $2020 ($000)
PG&E	2,067	1,311	600	$ 1,239	$ 7,868
SCE	2,170	1,376	630	$ 1,300	$ 8,260
SDG&E	494	313	143	$ 296	$ 1,879
SMUD	0	0	0	$ -	$ -
LADWP	0	0	0	$ -	$ -
NorCalMunis	0	0	0	$ -	$ -
SoCalMunis	0	0	0	$ -	$ -
Total	**4730.4**	**3000**	**1374**	**$ 2,835**	**$ 18,006**

14. Demand Response Resources

A. Overview

Demand response is the ability to directly control, or signal through prices or other means, consumption changes of electricity at times of the system peak. The level of demand response assumed to be in place in California primarily affects the amount of new generation that needs to be built to meet reserve margins and maintain reliability in the California system. Since demand response changes the 'load shape' in California, and the number of power-plants that are operating during the peak, demand response changes the dispatch of the system and therefore the GHG emissions levels.

B. Treatment of Demand Response in the GHG Modeling

The Energy Action Plan II sets a goal of demand response for California of 5% of peak load. This key action is accompanied by actions designed to incorporate demand response into the capacity planning process and to coordinate investor-owned utility and customer-owned utility demand response efforts. Therefore, the GHG Model assumptions on demand response are the following;

- Demand response levels in 2020 are equal to 5% of the 1 in 2 probability CA peak load forecast
- Demand response counts towards resource adequacy and reserve margins
- Peak load includes both investor-owned and publicly-owned utilities
- Energy consumption reduced during demand response events is replaced by increased energy consumption in other periods.

C. Data sources for Assumptions

The primary data source for these assumptions are the goals stated in the Energy Action Plan II document, along with the other key actions for demand response in EAP II intended to coordinate between IOUs and POUs as well as count demand response in resource planning. The following excerpts from EAP II highlight each of these assumptions.

Energy Action Plan II, Demand Response Key Actions, 2005

3. Identify and adopt new programs and revise current programs as necessary to achieve the goal to meet **five percent demand response** by 2007 and to make dynamic pricing tariffs available for all customers.

10. Incorporate demand response appropriately and consistently into the **planning** protocols of the CPUC, the CEC, and the CAISO.

12. **Coordinate IOU demand-response programs with customer-owned utility demand-response efforts** to provide a comprehensive, statewide contribution to California's resource adequacy portfolio.

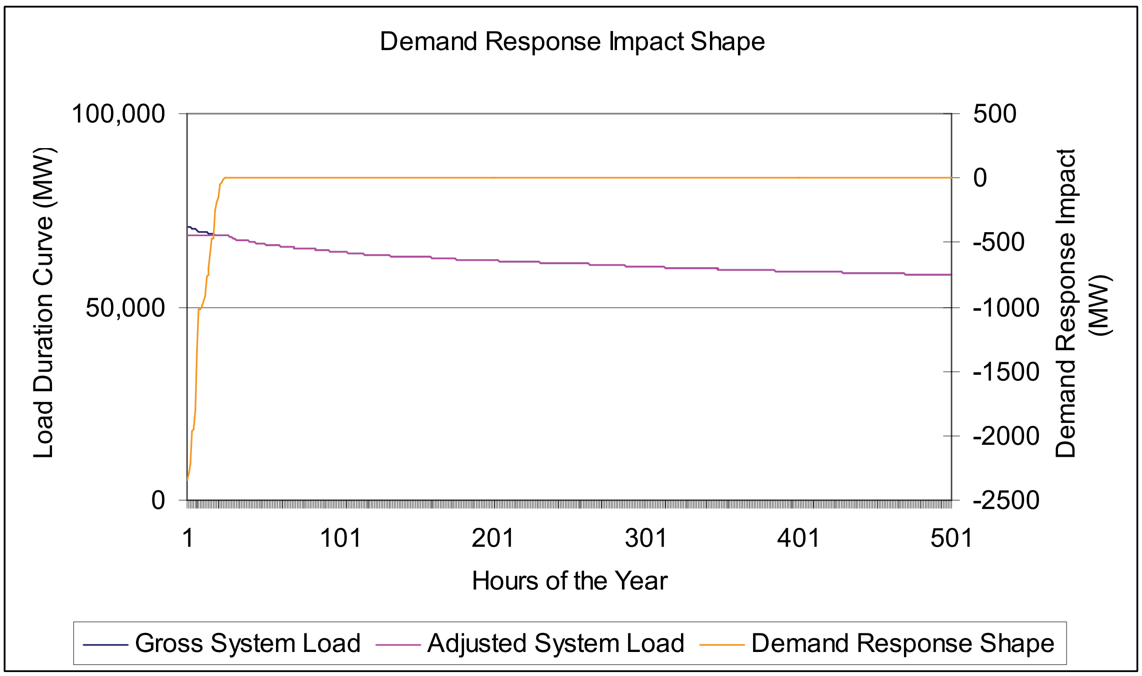
Highlights Added

The final assumption is the change in net energy consumption change including the energy reductions during the DR event net of any increases in consumption before or after the demand response event. The net energy consumption depends on a number of factors including the end-uses that are affected, and customer behavior. For example, demand response on HVAC commonly results in a 'bounce back' after the event and the equipment brings the conditioned space back to the desired temperature. Similarly, production schedules that are moved in time to reduce load during the demand response events would not result in a change in net energy. For this reason, the conservative and simplifying assumption that demand response results in no net energy savings has been made.

D. Discussion of Methodology

The approach to include demand response in the PLEXOS production simulation model is to adjust the load shape by hour to account for the peak load reduction and energy effects. This adjustment is the demand response impact. The following illustrative load duration curve shows the approach. Starting with a gross system load peak of 72,000 MW in 2020 (note this is illustrative – actual peak used is in the load forecast documentation) 5% demand response is equivalent to 3,600MW. Therefore, assuming demand response, the peak the load is reduced by 3,600MW to 68,400MW. In other high load hours, demand response also reduces load to 68,400MW. The figure shows the top 500 hours and the gross and net load duration curves with and without demand response. The demand response impact is shown on the right hand side axis for each hour. The peak hour reduction is 3,600MW, and the peak load is reduced in smaller amounts until hour 25 (based on the illustrative curve) when demand response is no longer needed to reduce peak load below 5% of peak. Note that although on this scale the demand response appears to be zero, it is actually a small positive to provide no net energy change over the course of the year.

California System Load, Load Net of Demand Response an Demand Response Impact Shape for Top 500 Hours of the Year



15. There is no Section 15

16. New Wind Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Wind generation currently provides about 2% of the electricity used to serve California loads.[24] Within the WECC as a whole, wind generation accounts for about 3% of electricity supply.[25] Most of California's current wind generation comes from wind parks located in the Tehachapi, Altamont, Solano, Pacheco and San Gorgonio areas, which have persistent high winds as terrain-induced and atmospheric forces drive air mass between the coastal regions and the Central Valley. Wind generation is typically treated as a must-take resource, as it is currently not dispatchable and operates when the wind is available.

Electric generation from wind resources is not a significant GHG emissions producer. The California emissions inventory does not include lifecycle GHG emissions from upstream and downstream processes including materials and construction, thus, the emissions intensity of wind generation is essentially zero.[26] Wind is therefore a preferred resource for AB32 compliance. Wind is also a qualifying technology for the California Renewables Portfolio Standard (RPS). Because the wind resource is significant and relatively competitive with fossil generation costs, this technology is poised to become a major component of new low-carbon energy supply in California, and many new wind projects have been proposed or are under development. With wind technology itself becoming increasingly mature, the key issues facing greater wind deployment are transmission interconnection and the reliable integration of high percentages of intermittent generation into the grid.

Base Case Resource, Cost, and Performance Assumptions

Table A gives the base case resource costs and performance assumptions for new wind generation used in the GHG calculator. The reference technology to which these assumptions apply is an onshore 50 MW wind park composed of 2.5 MW asynchronous generators. These costs and assumptions do not apply to offshore wind development.

Resource class and availability

Assumptions shown in Table A are based on a number of sources. The capital costs and O&M costs vary depending on the location of the wind generation and the quality of the wind resource.

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[24] The CEC 2006 Net System Power Report shows 4,927 GWh of specified wind generation, and 443 GWh of wind in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[25] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[26] CARB 2007.

For consistency throughout the Western Electricity Coordinating Council (WECC) area[27], wind resource availability estimates shown in Table A are based on the GIS resource potential dataset from NREL, which is also used in the national modeling efforts using NREL's Wind Deployment System (WinDS) model. NREL's data from California is from the California high-resolution wind resource assessment funded by the Energy Commission[28]. For all windy land area, NREL assigns a Wind Class rating ranging from 1 to 7 based on estimated wind power at a specific height above the ground (i.e. 10m or 50m)[29]. Land area in Classes 3 to 7 (6.4 m/s to 12 m/s) at 50 m elevation offers some of the best potential for wind generation. The wind resources in Class 1 to 2 are not sufficient to power state-of-the-art wind technologies.

The NREL dataset also excludes a large subset of windy locations based on the following criteria:

Environmental Exclusions

(1) 100% of National Park Service and Fish & Wildlife Service managed lands
(2) 100% of federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river or inventoried roadless area.
(3) 100% of state and private lands equivalent to criteria 1 and 2, where GIS data is available.
(4) 50% of remaining Forest Service lands, including National Grasslands.
(5) 50% exclusion of remaining Department of Defense lands
(6) 50% exclusion of state forest land, where GIS data is available

Land Use Exclusions

(7) 100% of airfields, urban, wetland and water areas.
(8) 50% of forests not on ridge crests

Other Exclusions

(9) All areas of slope > 20%100% of area within 3 kilometers of squares already excluded for other reasons
(10) All areas that lack a density of 5 square kilometers with Class 3 or better resources within the surrounding 100 square kilometer area

NREL's dataset groups the filtered wind resources by class in 98 regions within the WECC region of the U.S. Gross resource potential in these regions varies enormously, ranging from 4 MW (in the El Paso, Texas region) to 314,704 MW (in the southwestern Wyoming region). WECC-wide, the resulting technical wind potential is estimated at 2,437,155 MW, more than twice the existing electrical generating capacity of the United States.

To reduce this technical potential to a more practical economic potential, for zones outside of California the GHG calculator includes wind resource potential of Class 5 and above, and

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[27] The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. (WECC website http://www.wecc.biz/wrap.php?file=wrap/about.html)

[28] CEC Report 500-02-055F, November 2002

[29] NREL Wind Class Table http://www.nrel.gov/gis/wind.html

lower classes only if sufficient local transmission capacity already exists. Comparable GIS-based wind resource data were not available for British Columbia or Alberta, so estimates were added for those regions from more narrowly filtered, project-based estimates in utility long-term plans. 4,600 MW of wind potential have been added for British Columbia, and 2,000 MW of wind potential has been added for Alberta. An additional 10,000 MW in Alberta that are not identified as development bundles were assigned a low resource class value of 3 and thus not included in the filtered total. For California, all resource classes are included (and assigned at the county level, which is a smaller spatial scale – for details see "California Resource Zones" report).

After applying these additional filters, a total of 249,208 MW of wind resource potential remains for the entire WECC in the GHG model.

Location and Performance

The economic performance of a wind plant is a function of its annual energy output, which in NREL's model is a function of wind class.[30] The NREL model assigns a 40% average capacity factor to a reference plant in a Class 5 location. Other sources, including EIA, CEC, and AWEA, assign a 34% to 37% capacity factor for a Class 5 site.[31] In the GHG calculator, the NREL capacity factors have been scaled downward to match the other data sources 34% capacity factor estimate for Class 5 resources, resulting in the following capacity factors by class:

Class 7: 40.0%
Class 6: 37.4%
Class 5: 34.0%
Class 4: 30.6%
Class 3: 27.2%

The base capital cost for new wind plants is $1,635/kW, prior to applying zonal cost multipliers (see Table B). This value is derived from EIA *2007 AEO* cost assumptions, adjusted for inflation, recent increases in the cost of materials, and financing costs during construction to bring the costs into line with the results of the 2007 AWEA *Wind Vision* report, which is the most current, industry-based cost study available. Base case variable O&M costs are $0/MWh and fixed O&M costs are $30.70/kW-year, based on adjusted EIA *2007 AEO* cost assumptions (see "Financing and Incentives" report).

Table A. Wind Cost, Resources, & Performance

	2008 value	2020 base case value	2020 tech growth case	Range of 2008 values in model	Sources

[30] As a convention, NREL's dataset assumes that any square kilometer containing wind resources has a potential capacity of 5 MW, while the resource class at that location represents the annual energy output.
[31] EIA 2007, CEC 2007, and AWEA *Wind Vision* (forthcoming).

Base generation capital cost ($/kW)	$1,635[1, 2]	$1,635	$1,553 (5% reduction from base value)	$1,504 - $1,962[2]	Base case: [AWEA, 2007] Tech growth case: [AWEA, 2007]
AFUDC Multiplier (%)	105.9%	105.9%	105.9%	105.9%	[CEC Beta Model, 2007]
Variable O&M ($/MWh)	$0	$0	$0	$0	[EIA, 2007]
Fixed O&M ($/kW-yr)	$30.70[3]	$30.70	$30.70	$28.25 – $36.84[2]	[EIA, 2007]
Gross resource in WECC (MW)	2,437,155	2,437,155	2,437,155	2,437,155	[NREL GIS data, 2006]
Filtered resource in CA (MW)	53,044	53,044	53,044	53,044	[NREL GIS data, 2006 less TEPCC 2008 existing]
Filtered resource in Rest-of-WECC (MW)	255,808	255,808	255,808	255,808	[NREL GIS data, 2006 less TEPCC 2008 existing]
Capacity factor (%)	34%	34%	34%	27% - 40%	[EIA, 2007]

Notes:
[1]Base value originally reported in 2005$ from EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 15.0% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%. This value closely aligns with cost in forthcoming AWEA 2007 Wind Vision report, which estimates cost of $1,650 (in 2006$).
[2]Capital costs and fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest regional multiplier is WY (0.92); highest multiplier is CA (1.20)
[3]Fixed O&M cost originally reported by EIA in 2005$. Cost has been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Resource Potential and Zonal Levelized Costs

Table B shows resource potential and base case levelized costs for new wind generation in each of the twelve WECC zones used in the GHG calculator. The levelized costs are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A, levelizing the costs over the financing period , and dividing by the expected energy production. Merchant financing is assumed (see "Financing and Incentives" report). The base case range of busbar levelized cost of energy (LCOE) for wind generation in the WECC is $65-125/MWh.

Covered in separate reports are other costs associated with new wind generation in addition to the busbar costs. They include :

- transmission interconnection and long-distance transmission costs,
- firming costs to provide reliable capacity, and
- cost of additional system resources for ramping, regulation, and ancillary services to integrate intermittent resources, are covered in separate reports

Table B. Wind Busbar Levelized Costs by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$1,635**	**$31**		**34%**		**308,852**
AB	1.00	$1,635	$31	$0.00	27% - 40%	$70 - $104	11,986
AZ-S. NV	1.00	$1,635	$31	$0.00	31% - 40%	$70 - $91	1,826
BC	1.00	$1,635	$31	$0.00	34% - 40%	$70 - $83	4,601
CA	1.20	$1,962	$37	$0.00	27% - 40%	$84 - $125	53,044
CFE	1.00	$1,635	$31	$0.00	27% - 40%	$70 - $104	5,020
CO	0.97	$1,586	$30	$0.00	34% - 40%	$68 - $80	4,883
MT	1.02	$1,668	$31	$0.00	34% - 40%	$72 - $84	54,437
NM	0.96	$1,569	$29	$0.00	31% - 40%	$68 - $87	10,805
N. NV	1.09	$1,782	$33	$0.00	27% - 40%	$77 - $114	5,523
NW	1.11	$1,815	$34	$0.00	27% - 40%	$78 - $116	15,489
UT-S. ID	1.00	$1,635	$31	$0.00	31% - 40%	$70 - $91	2,601
WY	0.92	$1,504	$28	$0.00	34% - 40%	$65 - $76	138,637

Notes:
[1]All values shown in 2008 dollars.
[2]Capital Cost & Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Busbar levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, (d) tax liability and credits. It does not include interconnection and transmission costs, capital cost for resources needed to firm wind output, net energy benefit provided from firming resource required for wind resources, or integration costs.
[4]NREL does not filter out existing resources from resource potential data. Net resource potential shown above represents NREL's resource potential estimate net of existing capacity in the TEPPC database as of 2008.

Sources

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http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf.

US DOE, "Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends," May 2007. http://www.nrel.gov/docs/fy07osti/41435.pdf

17. New Biomass and Biogas Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Biomass generation currently provides about 2% of the electricity used to serve California loads.[32] Within the WECC as a whole, biomass generation is somewhat less than 2% of the total electricity supply.[33] Biomass is an umbrella term for a number of different technologies and fuel sources, including wood, forestry waste, crop waste, dedicated biomass crops such as switchgrass, municipal solid waste (MSW), landfill gas (LFG), and gases produced from dairy wastes and municipal wastewater treatment. In the GHG calculator and in the tables below, for simplicity these different technologies are grouped into two kinds: biomass and biogas. Biomass refers to technologies that burn solid biomass fuels and use the heat to operate a steam turbine. Biogas refers to technologies that burn gaseous biomass fuels in a combustion turbine or reciprocating engine.[34]

When considered on a once-through basis, biomass combustion produces GHG emissions, with typical emission factors for solid biomass of approximately 190 pounds of CO_2 per million Btu, and for biogas of different types of approximately 115 pounds of CO_2 per million Btu. However, there are no net CO_2 emission from biomass generation when the entire biomass fuel cycle (carbon cycle) is taken into account. Therefore, in the CARB inventory and reporting requirements, CO_2 emissions from the CARB-adopted categories of "biomass," "wood," "landfill gas," "digester gas," and "other biomass" are considered to be zero. CO_2 emissions for the "biogenic fraction of MSW" are also considered to be zero. Only the "fossil fraction of MSW" is considered to produce CO_2 emissions. When these emissions are added to the small emissions of N_2O and CH_4 from all forms of biomass, biomass generation of all kinds accounts for 0.4% of electricity sector emissions.[35] Biomass and biogas are considered qualifying resources for the California Renewables Portfolio Standard and are preferred resources for AB32 compliance.

Reference Case Resource, Cost, and Performance Assumptions

[32] The CEC 2006 Net System Power Report shows 5,735 GWh of specified biomass generation and 550 GWh of biomass in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.

[33] CEC 2007 IEPR Scenarios, 2009 Scorecard.

[34] Biomass-derived liquids such as ethanol, biodiesel, and Fischer-Tropsch liquids have high value competing uses such as transportation fuels and chemical feedstocks, and are not treated here as fuel for electricity generation. Advanced biomass generation using gasification with a combined cycle generator is considered unlikely to be commercialized by 2020.

[35] CARB 2007, http://www.arb.ca.gov/cc/ccei/inventory/inventory.php, inventory values for 2004, calculation by author.

Tables A1 and A2 give the reference case resource, cost, and performance assumptions for biomass and biogas generation, respectively. Capital cost assumptions are derived from the 2005 California Biomass Collective report for the CEC, and O&M costs are derived from EIA's *2007 Annual Energy Outlook*.[36] In both reports, costs are generally too low relative to current reported values, as they do not reflect recent capital cost increases resulting from higher materials costs and unfavorable exchange rates. The Table A1 and A2 reference case values are adjusted to reflect these increases.

The sources cited above yield a base overnight capital cost $3,737/kW for biomass, and $2,554 for biogas, prior to adjusting for financing costs during construction costs and zonal cost multipliers, but after adjustment for inflation and recent increases in the cost of materials. Reference case variable O&M costs for biomass are $3.19/MWh and fixed O&M costs are $54.04/kW-year. For biogas they are $0.01/MWh and fixed O&M costs are $115.77/kW-year

The theoretical resource potential for biomass generation is significant in California, with sufficient resources to produce more than 10,000 MW if available biomass fuels were dedicated to electricity generation. In addition, the Governor of California has issued an executive order that biomass generation should constitute 20% of total RPS generation in 2010 and 2020, and a joint agency task for has developed a state Bioenergy Action Plan to meet this goal.[37] However, there are a number of factors that make the likely developable potential more modest, including lack of reliable long-term biomass fuel supplies, competition with transportation and other sectors for feedstocks, land use and environmental restrictions, high O&M costs associated with burning fuels containing many impurities, and insufficient incentives to justify the effort and expense of developing small projects, such as dairy biogas digesters. For these reasons, many experts in the field expect only a fraction of California or the WECC's biomass potential to be developed in the near term.

Table A1 and A2 give estimates of the likely developable resource as 600 MW of solid biomass and 300 MW of biogas, respectively, based on the California Biomass Collaborative study and interviews with experts. For the other zones in the U.S. portion of the WECC, resource data from a 2005 NREL report that calculates biomass potential by state was scaled by the same factor that relates likely development to theoretical potential for California (i.e., 600 MW of biomass and 300 MW of biogas out of 10,000 MW potential). Additional data on biomass and biogas resources in Western Canada were derived from the BC Hydro 2006 Integrated Electricity Plan. The nominal reference case capacity factor for both biomass and biogas is 80%, which follows the *AEO 2007* assumptions.

Table A1. Biomass Cost, Resources, & Performance

	2008 value	2020 reference case value (2008$)	2020 tech growth case	Range of 2008 values in model	Sources

[36] EIA AEO Assumptions 2007, Table 39.
[37] California Energy Commission, "Bioenergy Action Plan for California," CEC-600-2006-010, July 2006.

Base overnight capital cost ($/kW)	$3,737[1]	$3,737	$3,475 (7% reduction from base value)	$3,438 - $4,484[2]	Reference case: [CA Biomass Collaborative, 2005] Tech growth case: [EIA, 2007]
AFUDC Multiplier (%)	105.9%	105.9%	105.9%	105.9%	[CEC, 2007 Beta Model]
Non-Fuel Base Variable O&M ($/MWh)	$3.19	$3.19	$3.19	$3.19	[EIA, 2007]
Base Fixed O&M ($/kW-yr)	$54.04[3]	$54.04	$54.04	$49.72 – $64.85[2]	[EIA, 2007]
Gross resource in WECC (MW)	2,361	2,361	2,361	2,361	[CA Biomass Collaborative; discussion with experts; NREL]
Filtered resource in CA (MW)	600	600	600	600	[CA Biomass Collaborative and discussion with experts]
Filtered resource in Rest of WECC (MW)	1,761	1,761	1,761	1,761	[NREL data, scaled to CA estimates.]
Nominal Heat Rate (BTU/kWh)	8,911	8,911	8,911	8,911	[EIA, 2007]
Capacity factor (%)	80%	80%	80%	80%	[EIA, 2007; Expert comments]

Notes:
[1]Base value originally reported in 2005$ by CA Biomass Collaborative 2005 report for a plant in CA. Cost has been adjusted: (a) from 2005$ to 2007$ at rate of 25% to account for recent price escalation, (b) from 2007$ to 2008$ at general inflation rate of 2.5%, and (c) divided by 1.2 to reflect that source data was for plant in CA, which has higher cost than other regions of WECC. (See below).
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007.
[3]Fixed O&M cost originally reported by EIA in 2005$. Cost has been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Table A2. Biogas Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources

Base overnight capital cost ($/kW)	$2,554[1]	$2,554	$2,367 (7% reduction from base value)	$2,350 - $3,065[2]	Reference case: [EIA, 2007] Tech growth case: [EIA, 2007]
AFUDC Multiplier (%)	115%	115%	115%	115%	[CEC, 2007 Beta Model]
Non-Fuel Base Variable O&M ($/MWh)	$0.01	$0.01	$0.01	$0.01	[EIA, 2007]
Base Fixed O&M ($/kW-yr)	$115.77[3]	$115.77	$115.77	$106.50 - $138.92[2]	[EIA, 2007]
Gross resource in WECC (MW)	592	592	592	592	[CA Biomass Collaborative; discussion with experts; NREL]
Filtered resource in CA (MW)	300	300	300	300	[CA Biomass Collaborative and discussion with experts]
Filtered resource in Rest of WECC (MW)	292	292	292	292	[NREL data, scaled to CA estimates.]
Nominal Heat Rate (BTU/kWh)	13,648	13,648	13,648	13,648	[EIA, 2007]
Capacity factor (%)	80%	80%	80%	80%	[EIA, 2007; Expert comments]

Notes:
[1]Base value originally reported in 2005$ in by EIA AEO 2007. Cost has been adjusted: (a) from 2005$ to 2007$ at rate of 25% to account for recent price escalation, (b) from 2007$ to 2008$ at general inflation rate of 2.5%.
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region is WY (0.92); highest multiplier is CA (1.20)
[3]Fixed O&M cost originally reported by EIA in 2005$. Cost has been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Resource Potential and Zonal Levelized Costs

Tables B1 and B2 show reference case levelized costs for new biomass and biogas generation, respectively, in each of the 12 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Tables A1 and A2. Merchant financing is assumed in the reference case (see "Financing and Incentives" report). The resulting reference case range of levelized cost of energy (LCOE) for biomass generation in the WECC is $126-153/MWh, and for biogas is $96-117/MWh. Other costs associated with new biomass and biogas generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports.

Table B1. Biomass Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$3,737**	**$54**		**80%**		**2,361**
AB	1.00	n/a	n/a	$3.73	n/a	n/a	-
AZ-S. NV	1.00	$3,737	$54	$3.73	80%	$133	43
BC	1.00	$3,737	$54	$3.73	80%	$133	208
CA	1.20	$4,484	$65	$3.73	80%	$153	600
CFE	1.00	n/a	n/a	$3.73	n/a	n/a	-
CO	0.97	$3,625	$52	$3.73	80%	$131	44
MT	1.02	$3,812	$55	$3.73	80%	$135	162
NM	0.96	$3,588	$52	$3.73	80%	$130	26
N. NV	1.09	$4,073	$59	$3.73	80%	$142	15
NW	1.11	$4,148	$60	$3.73	80%	$144	1,060
UT-S. ID	1.00	$3,737	$54	$3.73	80%	$133	181
WY	0.92	$3,438	$50	$3.73	80%	$126	22

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier. Cost entries of "n/a" indicate that no resources for that zone remained in the final filtered resource potential dataset.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Table B2. Biogas Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$2,554**	**$116**		**80%**		**592**
AB	1.00	n/a	n/a	$1.85	n/a	n/a	-
AZ-S. NV	1.00	$2,554	$116	$1.85	80%	$102	33
BC	1.00	$2,554	$116	$1.85	80%	$102	50
CA	1.20	$3,065	$139	$1.85	80%	$117	300
CFE	1.00	n/a	n/a	$1.85	n/a	n/a	-
CO	0.97	$2,478	$112	$1.85	80%	$100	59
MT	1.02	$2,606	$118	$1.85	80%	$103	5
NM	0.96	$2,452	$111	$1.85	80%	$99	18
N. NV	1.09	$2,784	$126	$1.85	80%	$109	15
NW	1.11	$2,835	$128	$1.85	80%	$110	88
UT-S. ID	1.00	$2,554	$116	$1.85	80%	$102	21
WY	0.92	$2,350	$107	$1.85	80%	$96	2

Notes:

[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier. Cost entries of "n/a" indicate that no resources for that zone remained in the final filtered resource potential dataset.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

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18. New Geothermal Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Geothermal generation currently provides a little less than 5% of the electricity used to serve California loads.[38] Within the WECC as a whole, geothermal constitutes less than 3% of the total electricity supply.[39] A large share of California's geothermal generation comes from The Geysers geothermal field in Sonoma County, where approximately 750 MW of capacity are generated from about 20 separate power plants. Since geothermal plants have low operating costs and constant energy input, they typically run year-round and have capacity factors similar to those of other baseload thermal generation.

Geothermal power uses the heat contained in subterranean geologic strata, typically in the form of hot water or brine trapped in porous rock that is brought to the surface in a well, to generate electricity. No fossil fuel is burned in the process, although geothermal generation typically does result in a small amount of fugitive CO_2 emissions. When these are taken into account, geothermal generation is responsible for 0.3% of electricity sector GHG emissions.[40] Geothermal is a preferred resource for AB32 compliance. Geothermal generation is also a qualifying technology for the California Renewables Portfolio Standard.

Reference Case Resource, Cost, and Performance Assumptions

Table A gives the reference case resource, cost, and performance assumptions for new geothermal generation used in the GHG calculator. The reference technology to which these assumptions apply is a new binary or dual flash generator with a minimum 100 degree Celsius geothermal resource.[41] These costs do not apply to Enhanced Geothermal Systems (EGS) such as hot dry rock, which are not expected to be commercially developed by 2020.

The cost of geothermal generation is highly site-specific, depending strongly on geothermal resource availability, resource quality, and distance from transmission. The estimate of geothermal resource availability by region in Table A is based on a site-specific dataset of resource availability and cost provided by EIA, which was used in the Renewable Fuels Module of the *Annual Energy Outlook 2007*. Data for CA and NV in the EIA dataset are based on a 2004 GeothemEx report for the CEC, "New Geothermal Site Identification and Qualification." The GeothemEx report provided a comprehensive estimate of MW potential and the site-specific exploration, confirmation and development capital costs, as well as fixed O&M costs, for 21 sites in California and 43 sites in Nevada.

Data for the rest of the U.S. portion of the WECC in the EIA dataset are based on the Western Governors Association (WGA) Clean and Diversified Energy Advisory Committee

[38] The CEC 2006 Net System Power Report shows 13,448 GWh of specified geothermal generation, and 260 GWh of geothermal in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[39] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[40] GHG emissions from geothermal generation fugitive CO_2 were 0.33 million metric tons in 2004. CARB 2007.
[41] EIA AEO Assumptions 2007, Table 39.

(CDEAC) 2006 Geothermal Task Force Report, which estimated a capital cost and O&M cost for 24 sites in WECC states outside California and Nevada. Two sites in British Columbia with a total of 185 MW of generation potential identified in the BC Hydro 2006 Integrated Energy Electricity Plan are also included. An additional 3,143 MW reported in WGA data for Tier 2 resource potential provided no specific cost estimates and after consultation with geothermal experts were filtered out of the available resource dataset as being of uncertain quality. Table A shows that out of a gross reported resource of 9,307 MW in the WECC, the filtered resource in the GHG calculator is 6,164 MW in the WECC, of which 3,008 are in California. These estimates take into account resources already developed in California and other WECC zones.

Because of its site dependence, costs for geothermal generation vary extremely widely. The sources cited above give a range of $1,582-19,451/kW for the listed sites, prior to applying financing costs during construction cost and zonal cost multipliers, but after adjustment for inflation and recent increases in the cost of materials. The reference overnight capital cost for typical new geothermal plants is $3011/kW. This value is based on the *AEO 2007* total cost assumption, adjusted as above (see Financing Assumptions Report). Reference case variable O&M costs are $0/MWh and fixed O&M costs are $166.83/kW-year. The reference case capacity factor is 90%, which follows the *AEO 2007* assumptions.

Table A. Geothermal Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources
Base overnight capital cost ($/kW)	$3,011[1]	$3,011	$2,981 (1% reduction from base value)	$1,582 - $19,451[2]	Reference case: [EIA, 2007] Tech growth case: [EIA, 2007] Range of values: [EIA site data, 2007]
AFUDC Multiplier (%)	122.4%	122.4%	122.4%	122.4%	[CEC, 2007 Beta Model]
Variable O&M ($/MWh)	$0	$0	$0	$0	[EIA, 2007]
Fixed O&M ($/kW-yr)	$166.83[3]	$166.83	$166.83	$156.64 - 226.26[2]	[EIA, 2007]
Gross resource in WECC (MW)	9,307[4]	9,307	9,307	9,307	[EIA site data, 2007 plus TEPPC new sites]
Filtered resource in CA (MW)	3,008	3,008	3,008	3,008	[EIA site data, 2007]
Filtered resource in Rest-of-WECC	3,156[4]	3,156	3,156	3,156	[EIA site data, 2007 plus TEPPC new

(MW)					sites]
Capacity factor (%)	90%	90%	90%	90%	[EIA site data, 2007]

Notes:

[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted: (a) from 2005$ to 2007$ at rate of 25% to account for recent price escalation, (c) from 2007$ to 2008$ at general inflation rate of 2.5%. Costs vary significantly by site, and base value from EIA represent "cost of the least expensive plant that could be built in the Northwest Power Pool region."

[2]Capital costs and Fixed O&M in model vary by specific geothermal site, based on site-specific cost estimates data from EIA. Regional cost multipliers are not used for geothermal, as site-specific costs are assumed to incorporate zonal cost variation.

[3]Fixed O&M cost originally reported by EIA in 2005$. Cost has been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

[4] EIA's capacity amounts represent estimated resource potential as of 2006. 55 MW of potential near Geysers in Northern California is included in the TEPPC data with an online year of 2007, and has been removed from the EIA resource potential estimate. Additionally, 180 MW of geothermal in Nevada and 27 MW in Utah-S. Idaho were included in TEPPC as new renewables to be added between 2008 and 2017, but these resources were either not listed in the EIA site data or the EIA sites were listed with a smaller MW potential than those in TEPPC. These resources have been added to the total resource potential.

Zonal Resource Potential and Zonal Levelized Costs

Table B shows resource potential and reference case levelized costs for new geothermal generation in each of the 12 WECC zones used in the GHG calculator. The costs are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A. With the site-specific capital costs and the performance and financing assumptions elsewhere (see "Financing and Incentives" report), the resulting reference case range of levelized cost of energy (LCOE) for geothermal generation in the WECC is $66-349/MWh. Other costs associated with new geothermal generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports.

Table B. Geothermal Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$3,011**	**$167**		**90%**		**6,219**
AB	1.00	n/a	n/a	$0.00	n/a	n/a	-
AZ-S. NV	1.00	n/a	n/a	$0.00	n/a	n/a	-
BC	1.00	$1,582 - $2,799	$213	$0.00	90%	$72 - $91	185
CA	1.20	$3,339 - $8,131	$157 - $226	$0.00	90%	$99 - $179	3,063
CFE	1.00	n/a	n/a	$0.00	n/a	n/a	-
CO	0.97	$5,828	$191	$0.00	90%	$134	20
MT	1.02	n/a	n/a	$0.00	n/a	n/a	-
NM	0.96	$5,664 - $5,696	$191 - $226	$0.00	90%	$131 - $137	80
N. NV	1.09	$1,582 - $19,451	$157 - $226	$0.00	90%	$66 - $349	1,469
NW	1.11	$5,198 - $5,696	$157 - $213	$0.00	90%	$121 - $137	335
UT-S. ID	1.00	$3,011 - $5,729	$157 - $213	$0.00	90%	$87 - $136	1,067
WY	0.92	n/a	n/a	$0.00	n/a	n/a	-

Notes:
[1]All values shown in 2008$. Capital and Fixed O&M Costs for each site were originally reported in 2004$ in the EIA site data, and have been adjusted: (a) from 2004$ to 2005$ at general inflation rate of 2.5% (b) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (c) from 2007$ to 2008$ at general inflation rate of 2.5%. Cost entries of "n/a" indicate that no sites for that zone remained in the final filtered resource potential dataset.
[2]Capital Cost and Fixed O&M Cost ranges for each zone reflect the range of EIA site-specific costs for all sites in each zone that remain after E3 applied site filters. Regional cost multipliers are not used for geothermal Capital Costs and fixed O&M Costs, as site-specific costs are assumed to incorporate zonal cost variation.
[3]Busbar Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.
[4]EIA's capacity amounts represent estimated resource potential as of 2006. 55 MW of potential near Geysers in Northern California is included in the TEPPC data with an online year of 2007, and has been removed from the EIA resource potential estimate.

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19. New Concentrating Solar Power (CSP) Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Concentrating solar power (CSP) generation currently provides 0.2% of the electricity used to serve California loads.[42] Within the WECC as a whole, CSP is currently a negligible component of electricity supply.[43] Almost all of California's current solar thermal generation comes from the 340 MW Solar Energy Generating Station (SEGS) solar trough plant in the Mojave desert, which began operation in the 1980s. However, a number of new CSP plants have recently been proposed in California and some are in the stage of contract negotiations between developers and utilities.

CSP does not produce significant GHG emissions. Lifecycle GHG emissions from upstream and downstream processes including materials, construction, and embedded energy in cooling water are not included in the California emissions inventory, and so the emissions intensity of CSP is zero.[44] CSP is therefore a preferred resource for AB32 compliance. CSP is also a qualifying technology for the California Renewables Portfolio Standard. Because the CSP resource is very large, this technology can potentially become a major component of new low-carbon energy supply in California, but costs are currently higher, and more uncertain, than many other resource types.

Reference Case Resource, Cost, and Performance Assumptions

Table A gives the reference case resource, cost, and performance assumptions for new CSP generation used in the GHG calculator. The reference technology to which these assumptions apply is a new 100 MW solar trough system with an oil working fluid transferring heat to a secondary water cooling system that operates a steam turbine. The reference design is assumed to have 6 hours of thermal storage and no natural gas backup, and be located in the Mojave desert.[45] These costs do not apply to other CSP technologies including power tower, Stirling, Fresnel, or concentrating PV. Although these technologies are represented in current utility contracts or procurement plans, none have been commercially demonstrated at large scale over a long time period. To the extent that these technologies prove less expensive than solar trough over the long run, the CSP cost assumptions used in the GHG model reference case will be conservative. Users preferring other values for CSP costs will be able to input these into the GHG calculator.

Resource class and availability

[42] The CEC 2006 Net System Power Report shows 616 GWh of specified solar generation, and 0 GWh of solar in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[43] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[44] CARB 2007.
[45] Black & Veatch, 2006.

The cost of CSP depends strongly on the quality of the solar resource at the plant location. The estimate of solar thermal resource availability in Table A is based on the GIS resource potential dataset developed by NREL, which was also used in the Western Governors' Association's 2006 CDEAC study of solar resources. For all land area in the WECC, the NREL data assigns a solar resource class from 1 to 5 based on the direct normal irradiation (DNI), a measure of the average solar energy arriving at a plane perpendicular to the sun's rays at that location (measured in kilowatt-hours per square meter per day). The best locations for solar thermal generation are assigned a resource class of 5, the next best a class of 4, and so on.

The NREL analysis applies the following filters to exclude solar thermal resources at:

(1) Locations with less than 6.75 kwh/m^2/day average annual DNI;
(2) Locations with greater than 1% slope;
(3) Locations in protected federal lands, such as parks, wilderness areas, and monuments;
(4) Locations in urban areas or over water;
(5) Any remaining locations that have less than 5 square kilometers of contiguous land area.

NREL's model then groups the filtered solar thermal resources for each resource class by region within the WECC, where each NREL region contains one or more counties. Of the 98 WECC regions in the NREL model, 31 have significant solar thermal potential after the filtering process described above, with a gross resource of 6,559,700 MW. E3 has further filtered this data by including only solar thermal resources of Class 4 and above (DNI of 7.50 kWh/m^2/day and higher), corresponding to the resources at sites that are currently under consideration for development. In California, an additional E3 filter restricts potential CSP sites to 1% of the total land area within each NREL region. After applying these filters, 358,202 MW of WECC-wide solar thermal resource potential remains in the model. This potential is concentrated entirely within the states of California, Arizona, Nevada, and New Mexico, with 89,117 MW in California.

Location and Performance

The economic performance of a CSP plant is a function of its annual energy output, which is related in turn to its capacity factor.[46] The capacity factor for a solar thermal plant varies depending on both design factors and location. The design factors include hours of storage capability, and the size and number of solar arrays used relative to the size of the steam turbine. The reference plant with 6 hours of storage capacity from the 2006 Black & Veatch study has a capacity factor of 40.4%, and is for a plant located in the California desert.[47] The GHG calculator then uses a formula from NREL's Excelergy model to adjust this base capacity factor of 40.4% in response to locational factors, primarily latitude and DNI (as well as cloud frequency).

[46] As a convention, NREL's dataset assumes that a square kilometer of solar thermal resource represents an equivalent capacity of 50 MW at any location, while the resource class at that location represents the annual energy output.
[47] Black & Veatch, 2006, p. 6-4.

Resource class is used to approximate DNI, while for latitude E3 used NREL's web-based solar resource maps to visually estimate a point in the center of the greatest concentration of solar thermal resource within each of the NREL solar regions. The resulting latitude and DNI were used to calculate the capacity factor of the solar thermal resources within the region.

The base overnight capital cost for new CSP plants is $3389/kW, prior to applying zonal cost multipliers and financing costs during construction costs (see Table B). This value is based on Black & Veatch 2006 cost assumptions, adjusted for inflation and recent increases in the cost of materials. (See "Financing and Incentives" report.) Reference case variable O&M costs for CSP are $0/MWh and fixed O&M costs are $53.45/kW-year. The reference case capacity factor is 40%, which follows the Black & Veatch 2006 design specifications.

Table A. CSP Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources
Base overnight capital cost ($/kW)	$3,389[1]	$3,389	$2,712 (20% reduction from base value)	$3,254 - $4,067[2]	Reference case: [Black & Veatch, 2006] Tech growth case: [Expert comments]
AFUDC Multiplier (%)	108.6%	108.6%	108.6%	108.6%	[CEC, 2007 Beta Model]
Non-Fuel Variable O&M ($/MWh)	$0	$0	$0	$0	[EIA, 2007]
Fixed O&M ($/kW-yr)	$53.45[3]	$53.45	$53.45	$51.31 - $64.14[2]	[EIA, 2007]
Gross resource in WECC (MW)	6,559,700	6,559,700	6,559,700	6,559,700	[NREL GIS data, 2006]
Filtered resource in CA (MW)	89,117	89,117	89,117	89,117[4]	[NREL GIS data, 2006]
Filtered resource in Rest-of-WECC (MW)	358,202	358,202	358,202	358,202[4]	[NREL GIS data, 2006]
Capacity factor (%)	40%	40%	40%	37-40%[5]	[Black & Veatch, 2006]

Notes:
[1]Base value originally reported in 2005$ in Black & Veatch 2006 report for a plant in CA. Cost has been adjusted: (a) from 2005$ to 2006$ at general inflation rate of 2.5%, (b) from 2006$ to 2007$ at rate of 5% to account for recent price escalation mentioned by experts but not factored into costs of 2006 report, (c) from

2007$ to 2008$ at general inflation rate of 2.5%, and (d) divided by 1.2 to reflect that source data was for plant in CA, which has higher cost than other regions of WECC. (see below).
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region with solar thermal resource is NM (0.96); highest multiplier is CA (1.20)
[3]Fixed O&M cost originally reported by Black & Veatch 2006 report in 2005$. Cost has been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.
[4]CSP resource potential estimated by NREL has been further filtered for this model. In California, the resource potential by NREL zone (composed of small groups of contiguous counties) has been restricted to not exceed 1% of the total land area of the zone. Outside of California, only resource potential in the highest two resource classes (Class 4 and 5) has been included in the model. Existing CSP resources as of 2008 in TEPPC have also been removed from the resource potential.
[5]Capacity factors in model vary by resource characteristics at site. See discussion below.

Zonal Resource Potential and Zonal Levelized Costs

Table B shows resource potential and reference case levelized costs for new CSP generation in each of the 12 WECC zones used in the GHG calculator. As described above, only 4 of these zones have CSP resources that pass the filter of Class 4 solar resources and above. The levelized costs are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A. With the site-specific capital costs and the performance described earlier, and using merchant financing assumptions (see "Financing and Incentives" report), the resulting reference case range of busbar levelized cost of energy (LCOE) for CSP generation in the WECC is $123-161/MWh. Other costs associated with new CSP generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports

Table B. CSP Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$3,389**	**$53**		**40%**		**447,319**
AB	1.00	n/a	n/a	$0.00	n/a	n/a	-
AZ-S. NV	1.00	$3,389	$53	$0.00	37% - 38%	$130 - $133	141,243
BC	1.00	n/a	n/a	$0.00	n/a	n/a	-
CA	1.20	$4,067	$64	$0.00	37% - 40%	$149 - $161	89,117
CFE	1.00	n/a	n/a	$0.00	n/a	n/a	-
CO	0.97	n/a	n/a	$0.00	n/a	n/a	-
MT	1.02	n/a	n/a	$0.00	n/a	n/a	-
NM	0.96	$3,254	$51	$0.00	39%	$123	66,897
N. NV	1.09	$3,694	$58	$0.00	37% - 40%	$137 - $146	150,062
NW	1.11	n/a	n/a	$0.00	n/a	n/a	-
UT-S. ID	1.00	n/a	n/a	$0.00	n/a	n/a	-
WY	0.92	n/a	n/a	$0.00	n/a	n/a	-

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier. Cost entries of "n/a" indicate that no resources for that zone remained in the final filtered resource potential dataset.

[3]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, (d) tax liability and credits.
[4]NREL does not filter out existing resources from resource potential data. Net resource potential shown above represents NREL's resource potential estimate net of existing capacity in the TEPPC database as of 2008, and filtered to include only 1% of land area from each NREL zone within California and only Class 4 and Class 5 resources outside of California.

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20. New Large and Small Hydroelectric Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Hydroelectric generation currently provides 15-25% of the electricity used to serve California loads, depending on the annual availability of hydro resources and the method of assigning generation to imports.[48] Within the WECC as a whole, hydro constitutes 20-30% of the total electricity supply.[49] Due to its versatility as a generation resource, hydro can be used for both baseload and load following. Typically, it is stored for release during peak hours when generation costs are high.

Hydroelectric generation does not produce significant GHG emissions. Lifecycle GHG emissions from dam materials and construction, reservoir flooding, and other upstream and downstream processes are not included in the California emissions inventory, and so the emissions intensity of hydro generation is zero.[50] Due to concerns about the environmental effects of large dams, only hydroelectric facilities of 30 MW of capacity or less, commonly referred to as "small hydro," are considered qualifying resources for the California Renewables Portfolio Standard. Small hydro is also a preferred resource for AB32 compliance.

Because of the distinction between small and large hydro (facilities of more than 30 MW), these resources are treated separately in the GHG calculator and in the discussion and tables below.

Reference Case Resource, Cost, and Performance Assumptions

Tables A1 and A2 give the reference case resource, cost, and performance assumptions for new large hydro and small hydro generation, respectively. The nominal reference technology to which these assumptions apply, following the EIA's *2007 Annual Energy Outlook*, is a new 500 MW hydro facility with reservoir storage.[51] However, the cost of hydroelectric generation is highly site-specific, depending strongly on hydrologic characteristics, site accessibility, and distance from transmission. The values used in the GHG calculator are for specific projects.

The zonal estimates of large and small hydro resource availability in the U.S. portion of the WECC are based on the EIA's dataset of site-specific resource availability and cost used in the Renewable Fuels Module of the *2007 AEO*. The EIA data includes all sites with the potential for projects of 1 MW or more "from new dams, existing dams without

[48] The CEC 2006 Net System Power Report shows 43,088 GWh of specified large hydro generation and 5,788 GWh of specified small hydro generation. It also shows, and 10,951 GWh of large hydro and 6,236 GWh of small hydro in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[49] CEC 2007 IEPR Scenarios, 2009 Scorecard. WECC average hydro is 246,000 GWh.
[50] CARB 2007.
[51] EIA AEO Assumptions 2007, Table 39.

hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Energy & Engineering Laboratory (INEEL). Annual performance estimates (capacity factors) were taken from the generally lower but site specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs 10 cents per kilowatt-hour or lower are included in the supply." Each site in the EIA hydro dataset contains a specific estimate of MW potential at the site, capital costs, fixed and variable O&M costs, capacity factor and indicators for whether a number of environmental factors or other factors may lower the probability of site development.

Based on conversations with experts in hydro development, siting, and environmental regulation, E3 filtered the EIA site list by *excluding any sites with environmental factors indicated that could negatively affect the probability of site development, including all potential sites that would require new dams.* The filtered resource availability shown in Tables A1 and A2 includes a total of 221 MW at 36 small hydro sites in California, and 514 MW at 95 small hydro sites in the rest of the U.S. portion of the WECC. For hydro at sites larger than 30 MW, the filtered list includes 440 MW at 5 sites in California, and 2,003 MW at 8 sites in the rest of the U.S. portion of the WECC.

The zonal hydro resource potential also includes data from the BC Hydro 2006 Integrated Energy Plan, which includes 100 MW of small hydro potential and 100 MW of large hydro for Alberta, and 1,521 MW of small hydro potential and 3,342 MW of large hydro potential for BC.

Because of its site dependence, costs for hydroelectric generation vary widely. The sources cited above give an overnight capital cost range of $1122-2193/kW for the listed large hydro sites, and $1758-5170/kW for the small hydro sites, prior to applying zonal cost multipliers and financing costs during construction, but after adjustment for inflation and recent increases in the cost of materials. The reference capital cost for typical new hydro facilities of both kinds is $2402/kW. This value is based on the *AEO 2007* total overnight cost assumption, adjusted as described above. Reference case variable O&M costs are $3.55/MWh and fixed O&M costs are $14.15/kW-year.

The nominal reference case capacity factor for both small and large hydro is 50%, which follows the *AEO 2007* assumptions, but capacity factors in the GHG calculator are based on site-specific evaluations in the resource dataset. The range of capacity factors for the included resources is 12-65%.

Table A1. Large Hydro Cost, Resources, & Performance (Facilities of 30MW and Above)

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources

Base overnight capital cost ($/kW)	$2,402[1,2]	$2,402	$2,402	$1,122 - $2,193[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no change.] Range of values: [EIA site data, 2007]
AFUDC Multiplier (%)	122.4%	122.4%	122.4%	122.4%	[CEC, 2007 Beta Model]
Base Non-Fuel Variable O&M ($/MWh)	$3.55[3]	$3.55	$3.55	$1.30 - $2.64[2]	[EIA site data, 2007]
Base Fixed O&M ($/kW-yr)	$14.15[3]	$14.15	$14.15	$5.28 - $12.96[2]	[EIA site data, 2007]
Gross resource in WECC (MW)	11,068	11,068	11,068	11,068	[EIA site data, 2007]
Filtered resource in CA (MW)	440[4]	440	440	440	[EIA site data, 2007]
Filtered resource in Rest of WECC (MW)	5,466[4]	5,466	5,466	5,466	[EIA site data, 2007]
Capacity factor (%)	50%	50%	50%	12% - 65%[2]	[EIA site data, 2007]

Notes:

[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted: (a) from 2005$ to 2007$ at rate of 25% to account for recent price escalation, (c) from 2007$ to 2008$ at general inflation rate of 2.5%. Costs vary significantly by site, and base value from EIA represent "cost of the least expensive plant that could be built in the Northwest Power Pool region."

[2]Capital costs, Fixed O&M costs, Variable O&M costs, and capacity factors in model vary by specific hydro site, based on site-specific cost estimates data from EIA. Capital costs and Fixed O&M also vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007.

[3]Fixed and Variable O&M costs originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

[4]Excludes sites in Western U.S. with environmental factors indicated that could negatively affect the probability of site development, including all potential sites that would require new dams

Table A2. Small Hydro Cost, Resources, & Performance (Facilities of Less than 30MW)

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources

Base overnight capital cost ($/kW)	$2,402[1]	$2,402	$2,402	$1,758 - $5,170[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no change.] Range of values: [EIA site data, 2007]
AFUDC Multiplier (%)	122.4%	122.4%	122.4%	122.4%	[CEC, 2007 Beta Model]
Base Non-Fuel Variable O&M ($/MWh)	$3.55[3]	$3.55	$3.55	$2.50 - $5.72[2]	[EIA site data, 2007]
Base Fixed O&M ($/kW-yr)	$14.15[3]	$14.15	$14.15	$11.37 - $30.64[3]	[EIA site data, 2007]
Gross resource in WECC (MW)	5,351	5,351	5,351	5,351	[EIA site data, 2007]
Filtered resource in CA (MW)	221[4]	221	221	221	[EIA site data, 2007]
Filtered resource in Rest of WECC (MW)	2,134[4]	2,134	2,134	2,134	[EIA site data, 2007]
Capacity factor (%)	50%	50%	50%	22% - 65%[3]	[EIA site data, 2007]

Notes:
[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted: (a) from 2005$ to 2007$ at rate of 25% to account for recent price escalation, (c) from 2007$ to 2008$ at general inflation rate of 2.5%. Costs vary significantly by site, and base value from EIA represent "cost of the least expensive plant that could be built in the Northwest Power Pool region."
[2]Capital costs, Fixed O&M costs, Variable O&M costs, and capacity factors in model vary by specific hydro site, based on site-specific cost estimates data from EIA. Capital costs and Fixed O&M also vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007.
[3]Fixed and Variable O&M costs originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.
[4]Excludes sites in Western U.S. with environmental factors indicated that could negatively affect the probability of site development, including all potential sites that would require new dams

Zonal Resource Potential and Zonal Levelized Costs

Tables B1 and B2 show reference case levelized costs for new large and small hydro generation, respectively, in each of the 12 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Tables A1 and A2. With the site-specific performance and capital costs and the merchant financing assumptions described in the "Financing and Incentives" report, the resulting reference case range of levelized cost of energy (LCOE) for small hydro generation in the WECC is $82-289/MWh, and for large hydro is $68-365/MWh.

Other costs associated with new hydro generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports.

Table B1. Large Hydro Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$2,402**	**$14**		**50%**		**5,885**
AB	1.00	$2,002	$6	$0.00	50%	$93	100
AZ-S. NV	1.00	n/a	n/a	$0.00	n/a	n/a	-
BC	1.00	$1,240 - $2,002	$6 - $10	$0.00	20% - 50%	$78 - $163	3,342
CA	1.20	$1,486 - $2,193	$9 - $13	$0.00	12% - 57%	$93 - $365	440
CFE	1.00	n/a	n/a	$0.00	n/a	n/a	-
CO	0.97	n/a	n/a	$0.00	n/a	n/a	-
MT	1.02	n/a	n/a	$0.00	n/a	n/a	-
NM	0.96	n/a	n/a	$0.00	n/a	n/a	-
N. NV	1.09	n/a	n/a	$0.00	n/a	n/a	-
NW	1.11	$1,122 - $2,028	$5 - $11	$0.00	15% - 37%	$120 - $230	1,861
UT-S. ID	1.00	$1,760 - $2,031	$9 - $11	$0.00	25% - 65%	$68 - $170	143
WY	0.92	n/a	n/a	$0.00	n/a	n/a	-

Notes:

[1]All values shown in 2008$. Cost entries of "n/a" indicate that no sites for that zone remained in the final filtered resource potential dataset.

[2]Capital Cost and Fixed O&M Cost ranges for each zone reflect the range of EIA site-specific costs for all sites in each zone that remain after E3 applied site filters. Site-specific capital Cost and Fixed O&M Cost are also adjusted by multiplying by the zonal cost multiplier.

[3]Capacity factor range by zone reflect the range of EIA site-specific capacity factors for all sites in each zone that remain after E3 applied site filters.

[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Table B2. Small Hydro Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$2,402**	**$14**		**50%**		**2,356**
AB	1.00	$3,288	$19	$0.00	50%	$144	100
AZ-S. NV	1.00	n/a	n/a	$0.00	n/a	n/a	-
BC	1.00	$2,002 - $2,803	$19	$0.00	50%	$99 - $127	1,521
CA	1.20	$2,539 - $5,170	$14 - $31	$0.00	25% - 65%	$105 - $289	221
CFE	1.00	n/a	n/a	$0.00	n/a	n/a	-
CO	0.97	n/a	n/a	$0.00	n/a	n/a	-
MT	1.02	$2,158 - $2,547	$12 - $14	$0.00	35% - 65%	$78 - $164	37
NM	0.96	n/a	n/a	$0.00	n/a	n/a	-
N. NV	1.09	$2,559 - $4,593	$24 - $27	$0.00	35% - 54%	$164 - $181	10
NW	1.11	$1,758 - $4,782	$13 - $28	$0.00	23% - 65%	$88 - $284	230
UT-S. ID	1.00	$2,092 - $4,255	$11 - $25	$0.00	22% - 65%	$82 - $255	221
WY	0.92	$2,276 - $3,877	$13 - $23	$0.00	62% - 65%	$85 - $129	17

Notes:
[1]All values shown in 2008$. Cost entries of "n/a" indicate that no sites for that zone remained in the final filtered resource potential dataset.
[2]Capital Cost and Fixed O&M Cost ranges for each zone reflect the range of EIA site-specific costs for all sites in each zone that remain after E3 applied site filters. Site-specific capital Cost and Fixed O&M Cost are also adjusted by multiplying by the zonal cost multiplier.
[3]Capacity factor range by zone reflect the range of EIA site-specific capacity factors for all sites in each zone that remain after E3 applied site filters.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

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21. New Combined Cycle Gas Turbine (CCGT) Generation

Resource, Cost, and Performance Assumptions

Current Status of Technology

Natural gas-fired generation currently provides 35-45% of the electricity used to serve California loads, depending on hydro conditions and the method used to assign generation to imports.[52] Within the WECC as a whole, natural gas-fired generation constitutes about one-quarter of the total electricity supply.[53] Natural gas is used in base load, intermediate cycle, and peaking units. In California, more than three-quarters of natural gas generation comes from combined cycle gas turbines (CCGT) operated as baseload and intermediate cycle units.

Natural gas combustion is the second most important source of GHG emissions in the electricity sector after coal, with a typical value of 117 pounds of CO_2 emitted per million Btu of natural gas burned. Lifecycle GHG emissions from upstream and downstream processes such as plant construction, natural gas extraction, and embedded energy in cooling water, are not included in the California emissions inventory, while methane (CH_4) emissions from the transport of natural gas are included but not in the electricity sector inventory. Within the WECC, natural gas-fired generation is currently responsible for about 25% of total sector emissions. Determining the natural gas emissions for which California loads are responsible is a difficult question that depends on the method used to assign generation to imports, but natural gas under known California ownership and long-term contracts produces about 35% of electricity sector emissions in the latest draft California Emissions Inventory, and could be more than 50%.[54]

The state of California is currently addressing the question of the plant retirement schedule for older and relatively inefficient natural gas plants, many of which are essential to power system reliability due to their location within load pockets. New environmental requirements associated with cooling water use could also affect the retirement schedules and heat rates of coastal natural gas steam turbine and CCGT plants.

Combined-cycle gas turbine (CCGT) power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam turbine generator, which greatly increases the plant efficiency at little additional capital cost. Additional generating capacity can be obtained by enlarging

[52] The CEC 2006 Net System Power Report shows 106.968 GWh of specified natural gas generation, and 15,258 GWh of natural gas in unspecified imports, out of a total gross system power of 294,865 GWh in 2006. Under the reporting methodology of Griffin and Murtishaw, the presumed share of natural gas generation in unspecified inputs is substantially larger, and coal and hydro proportionally less.

[53] CEC 2007 IEPR Scenarios, 2009 Scorecard.

[54] For 2004, the most recent year included in draft inventory, natural contributed 35.1 million metric tons out of a total of 100.1 million metric tons of GHGs generated to serve California loads (CARB 2007, calculation by author.) If the Net System Power generation figures are used, they imply emissions from natural gas of 51.4 million metric tons (for an assumed average heat rate of 8,000 Btu/kWh).

the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). The CCGT is frequently identified by utilities and regulators as the least-cost fossil fuel alternative for providing new generation while maintaining relatively low emissions. The plants are reliable and efficient with relatively low capital costs and short-lead times.

Reference Case Resource, Cost, and Performance Assumptions

Table A shows the resource, cost, and performance assumptions for new natural gas combined cycle generation used in the GHG model reference case. The reference technology to which these assumptions apply is a new 500 MW CCGT.[55] These costs do not apply to as yet uncommercialized CCGTs with advanced combustion turbines, or to CCGTs with carbon capture and storage.

The values in Table A are derived from the CPUC's Market Price Referent Proceeding (R. 04-04-026, Resolution E-4118). The base capital cost for new CCGTs is $1054/kW for California ($878/kW for the United States as a whole), prior to adjusting for financing costs during construction (see "Financing and Incentives" report), per the MPR. Reference case non-fuel variable O&M costs are $2.58/MWh and fixed O&M costs are $11.89/kW-year. The unit has a heat rate of 6,917 Btu/kWh. The capacity factor of CCGT units is determined by the PLEXOS production simulation model.

Table A. Natural Gas CCGT Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources
Base overnight capital cost ($/kW)	$878	$878	$878	$807 - $1,054[2]	CPUC MPR Proceeding
AFUDC Multiplier (%)	115%	115%	115%	115%	[CEC 2007 Beta Model]
Non-Fuel Base Variable O&M ($/MWh)	$2.58[3]	$2.58	$2.58	$2.58	CPUC MPR Proceeding
Base Fixed O&M ($/kW-yr)	$11.89[3]	$11.89	$11.89	$10.94 - $14.27[2]	CPUC MPR Proceeding
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]

[55] CPUC Market Price Referent Proceeding (R. 04-04-026), Resolution E-4118: 2007 MPR Model E-4118.xls, "Install_Cap" tab.

Filtered resource in Rest-of-WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate (BTU/kWh)	6,917	6,917	6,917	6,917	CPUC MPR Proceeding
Capacity Factor	Determined by PLEXOS	Determined by PLEXOS	Determined by PLEXOS	Determined by PLEXOS	

Notes:
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20)

Zonal Levelized Costs

Table B shows reference case busbar levelized costs for new CCGT generation in each of the 12 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A, along with financing costs during construction, and are calculated based on merchant financing assumptions. Table B also shows reference case fuel costs ranging from $5.51 to $6.56 per million Btu across zones (see "Fuel Cost Forecast" report). With the performance and financing assumptions described earlier, the resulting reference case range of levelized cost of energy (LCOE) for CCGTs in the WECC is $68-83/MWh. Other costs associated with new CCGT generation – for example the costs of transmission interconnection and long-distance transmission – are discussed in separate reports.

Table B. Natural Gas CCGT Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr.)	Fuel Cost ($/MMBtu)	Capacity Factor	Busbar LCOE ($/MWh)	Net Resource Potential (MW)
Base Value	**1.00**	**$878**	**$11.89**	**-**	**90%**	**-**	**N/A**
AB	1.00	$878	$11.89	$5.52	90%	$ 70.24	N/A
AZ - S. NV	1.00	$878	$11.89	$6.40	90%	$ 77.75	N/A
BC	1.00	$878	$11.89	$5.68	90%	$ 71.60	N/A
CA	1.20	$1,054	$14.27	$6.54	90%	$ 82.92	N/A
CFE	1.00	$878	$11.89	$6.52	90%	$ 78.79	N/A
CO	0.97	$852	$11.53	$5.54	90%	$ 69.86	N/A
MT	1.02	$896	$12.13	$5.51	90%	$ 70.61	N/A
NM	0.96	$843	$11.41	$6.16	90%	$ 74.88	N/A
No. NV	1.09	$957	$12.96	$6.56	90%	$ 80.95	N/A
NW	1.11	$975	$13.20	$5.60	90%	$ 73.13	N/A
UT - S. ID	1.00	$878	$11.89	$5.64	90%	$ 71.30	N/A
WY	0.92	$808	$10.94	$5.51	90%	$ 68.60	N/A

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. The California price is based on the 2007 MPR nominal forecast value of $8.79/MMBtu, delivered to California generators. Fuel costs for other regions are based on the 2005

SSG-WI database, scaled to the 2020 California value. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Benchmarking CCGT Costs

Capital Costs

The MPR methodology relies on publicly available installed capital costs that reflect the actual cost of a range of CCGT projects in California that have been built in the last few years or are currently under construction. The MPR assumes a 500 MW GE F-series gas turbine with duct-firing and dry cooling. The 2007 MPR uses an average of the estimated cost of (a) the SDG&E Palomar Power Plant and (b) the SMUD Cosumnes Power Plant. After escalating to 2008$ using the Army Corp of Engineers (USACOE) Construction Cost Index resulting in estimates of $828 and $954/kW respectively. Adding adjustments for interconnection and dry cooling, the average capital cost for both plants is $1,054/kW (installed 2008$). The capital costs estimates, along with their average cost, are shown in Table C below, which compares this estimate to (a) the overnight costs used in the GHG calculator for a plant in California, and to (b) the CCGT capital costs from the CEC's 2007 Draft Cost of Generation (COG) Study for a 500MW plant with 50 MW of Duct Firing.

Table D: Installed Capital Cost Comparison (2008 $/kW)

Component	Palomar	Consumnes	Average for MPR	CEC COG
Base[1]	$828	$954	$848	$747
Interconnection		45		66
Env. Permits				30
Duct Firing				19
Other	150			
Subtotal	**$978**	**$999**	**$989**	**$862**
Dry Cooling	61	68		*48*[2]
TOTAL	**$1,040**	**$1,067**	**$1,054**	

Notes:
[1]All values shown in 2008$. CEC values have been adjusted from 2007$ to 2008$ using general inflation rate of 2.5%.
[2]The GHG Calculator cost installed cost shown here has been adjusted from overnight capital cost in Table B by multiplying by the financing during construction multiplier of 114.9%. It has also been adjusted for using the California regional cost multiplier of 1.2. The GHG Calculator costs represent cost at the busbar, and therefore do not include interconnection or permitting costs.
[2]The CEC COG reference case cost for a CCGT does not include the cost of dry cooling, a cost component which it displays separately as a "cost adder for less common component costs … that are not incorporate directly into the Model but can be entered exogenously into the Model."

The Northwest Power and Conservation Council's (NWPPC) 5th Power Plan also contains CCGT cost assumptions that serve as an additional point of reference for selecting the GHG

Calculator CCGT cost. It is important to compare to out of state estimates as well, because the cost are the costs used in the GHG Calculator are used for the selection of new resources throughout the WECC, not just in California. Table E below lists various assumptions regarding the CCGT capital costs, reference plant details, heat rate, and forecasted cost improvement from the GHG Calculator, the original EIA AEO 2007 assumptions, the 2007 MPR, the CEC's COG study and the Northwest Council's estimates.

Table E: Capital Cost Assumptions Comparison –EIA, MPR, NWPCC, CEC (2008$)

Source	2007 MPR/GHG Calc	EIA – Conv.	EIA – Adv.	CEC COG	NWPPC
Plant Description	500 MW GE F-Class gas turbine	250 MW Conventional CC	400 MW Advanced CC	500 MW GE 7F Gas Turbines with 50 MW duct firing	GE F-Class gas turbine in 2x1 combined-cycle. 540 MW + 70 MW duct firing
Cooling	Dry	Unspecified	Unspecified	Wet	Wet
Overnight Capital Cost ($/kW)		$649	$640		$640 [represents weighted avg of $688 for 540 MW combined cycle & $274 for 70 MW duct burners]
Installed Capital Cost ($/kW)	$1,054 (includes interconn. and other costs)			$883	
Heat Rate (Btu/kWh)	<u>Avg:</u> 6,917 <u>New:</u> 6,874	7,163 (for 2006 order date)	6,717 (for 2006 order date)	7,080	<u>New:</u> 6,880 (baseload) 9,290 (incremental duct-firing) 7,180 (full power) <u>Lifetime Average:</u> 7,030 (baseload) 9,500 (incremental duct-firing) 7,340 (full power)
Heat Rate Improvement	n/a	<u>2003-2010:</u> -0.23% <u>2003-2025:</u> **--0.20%**	<u>2003-2010:</u> **-0.39%** <u>2003-2025:</u> -0.64%		-0.5%/year (5% learning rate)
Technology Vintage Cost Change	n/a	<u>2003-2010:</u> **-0.69%** <u>2003-2015:</u> -0.47% <u>2003-2025:</u> 0%	<u>2003-2010:</u> **-0.78%** <u>2003-2015:</u> -0.53% <u>2003-2025:</u> 0%		-0.5%/year (constant dollar escalation)

[1]All values shown in 2008$. CEC values have been adjusted from 2007$ to 2008$ using general inflation rate of 2.5%. EIA values are adjusted from 2005$ to 2008$ at 2.5% per year. NWPCC values are adjusted from 2000$ to 2008$ at 2.5% per year.

Table F compares the heat rate, capacity factor and financing assumptions for the CCGT reference plant in the GHG Calculator, the 2007 CEC COG model and NWPCC both for Merchant and IOU financing.

Table F: Assumptions Comparison Cost Comparison for CCGT

Assumption	2007 MPR/ GHG Calc	EIA	CEC COG for Merchant	CEC COG for IOU	NWPPC For Merchant	NWPPC For IOU
Financing Party	Merchant[3]	Merchant	Merchant	IOU	Merchant	IOU
MW	500	250	500 MW w/ 50 MW duct firing	500 MW w/ 50 MW duct firing	540 MW w/ 70 MW duct firing	540 MW w/ 70 MW duct firing
Capacity Factor[1]	79%/90%	90%	60%	60%		
Heat Rate	6,917	7,183	7,080		6,710 (combined cycle) / 9,060 (duct firing)	
Debt	50%	70%	40%	50%	60%	50%
Equity	50%	30%	60%	50%	40%	50%
Cost of Debt	7.13%	***9.00%***[2]	6.50%	5.73%	7.8%	7.3%
Cost of Equity	12.78%	17.00%	15.19%	11.74%	15%	11%
WACC	8.50%	***11.40%***[2]	10.65%	7.57	8.9%	7.7%
Book Life	20	20	20	20	20	20

[1]The actual capacity factor of the CCGT in the GHG Calculator is determined by the PLEXOS production simulation model runs.
[2]Note: Cost of Debt (and WACC) for GHG model calculation is shown pre-tax. The other estimates have reduced the debt cost based on an assumed average tax rate.
[3]2007 MPR financing assumptions are shown for a Merchant financed plant that has a long-term contract with an IOU.

Sources

California Air Resources Board, Draft California Greenhouse Emissions Inventory, August 2007.

California Energy Commission, "2006 Net System Power Report," CEC-300-2007-007, CEC Staff Report, April 2007.

California Energy Commission, Beta Model for "Comparative Costs of California Central Station Electricity Generation Technologies," June 2007.

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U.S. Energy Information Administration, "2007 Annual Energy Outlook, Electricity Market Module Assumptions," DOE/EIA-0554, April 2007. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf.

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22. New Natural Gas Combustion Turbine Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Natural gas-fired generation currently provides 35-45% of the electricity used to serve California loads, depending on hydro conditions and the method used to assign generation to imports.[56] Within the WECC as a whole, natural gas-fired generation constitutes about one-quarter of the total electricity supply.[57] Natural gas is used in base load, intermediate cycle, and peaking units. In California, less than one-quarter of natural gas generation comes from combustion turbines (CT) operated primarily as peaking units.

Natural gas combustion is the second most important source of GHG emissions in the electricity sector after coal, with a typical value of 117 pounds of CO_2 emitted per million Btus of natural gas burned. Lifecycle GHG emissions from upstream and downstream processes such as plant construction and natural gas extraction are not included in the California emissions inventory, while methane (CH_4) emissions from the transport of natural gas are included but not in the electricity sector inventory. Within the WECC, natural gas-fired generation is currently responsible for about 25% of total sector emissions. Determining the natural gas emissions for which California loads are responsible is a difficult question that depends on the method used to assign generation to imports, but natural gas under known California ownership and long-term contracts produces about 35% of electricity sector emissions in the latest draft California Emissions Inventory, and could be more than 50%.[58]

The state of California is currently addressing the question of the plant retirement schedule for older and relatively inefficient natural gas plants, many of which are essential to power system reliability due to their location within load pockets (see Plant Retirements and Repowering Report). New environmental requirements associated with cooling water will not affect CTs, which have low water use.

The two basic classes of gas turbines are aeroderivative machines and industrial machines (also called "frame" or "heavy duty" turbines). Aeroderivative turbines, as the name suggests, are derived from the gas turbine engines used for aircraft. They are characterized by light weight, relatively high efficiency, quick startup, rapid ramp rates and ease of maintenance. Aeroderivative turbines tend to be more costly than industrial machines because of more severe operating conditions and more expensive materials. Industrial gas

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[56] The CEC 2006 Net System Power Report shows 106.968 GWh of specified natural gas generation, and 15,258 GWh of natural gas in unspecified imports, out of a total gross system power of 294,865 GWh in 2006. Under the reporting methodology of Griffin and Murtishaw, the presumed share of natural gas generation in unspecified inputs is substantially larger, and coal and hydro proportionally less.

[57] CEC 2007 IEPR Scenarios, 2009 Scorecard.

[58] For 2004, the most recent year included in draft inventory, natural contributed 35.1 million metric tons out of a total of 100.1 million metric tons of GHGs generated to serve California loads (CARB 2007, calculation by author.) If the Net System Power generation figures are used, they imply emissions from natural gas of 51.4 million metric tons (for an assumed average heat rate of 8,000 Btu/kWh).

turbines are designed for extended high-output duty. They are characterized by heavier components, somewhat lower efficiency, slower startup time, slower ramp rates and more complex maintenance procedures.

Reference Case Resource, Cost, and Performance Assumptions

Table A gives the reference case resource, cost, and performance assumptions for new natural gas combustion turbine generation used in the GHG calculator. The reference technology to which these assumptions apply is a new 160 MW CT.[59] These costs do not apply to as yet uncommercialized advanced CTs.

The values in Table A are largely derived from the EIA's *Annual Energy Outlook 2007*, which is considered a relatively unbiased source for new technology cost and performance estimates. However, *AEO 2007* costs are generally too low, as they do not reflect recent capital cost increases resulting from higher materials costs and unfavorable exchange rates. The Table A reference case values are adjusted to reflect these increases.

The natural gas fuel resource is assumed to be unlimited. The base capital cost for new CTs is $673/kW, prior to applying zonal cost multipliers (see Table B) and adjustments for financing costs during construction (see "Financing and Incentives" report). This value is based on the *AEO 2007* total overnight cost assumption, adjusted for inflation and recent increases in the cost of materials. Reference case non-fuel variable O&M costs are $3.62/MWh and fixed O&M costs are $12.28/kW-year.

The reference case performance values are a heat rate of 10,807 Btu/kWh (which follow the *AEO 2007* assumptions) and a capacity factor of 5% (which is based on the CEC 2007 Cost of Generation Draft report). [60]

Table A. Natural Gas CT Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources
Base overnight capital cost ($/kW)	$673[1]	$673	$673	$619 - $807[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no net change]
AFUDC Multiplier (%)	114.9%	114.9%	114.9%	114.9%	[CEC 2007 Beta Model]

[59] EIA AEO Assumptions 2007, Table 39.

[60] The nominal capacity factor of 5% is only used for ranking of potential new resource additions based on levelized costs (see "Resource Ranking and Selection" report). In the GHG model, production costs depend on the dispatch of each generating unit in the production simulation, which may be very different from the nominal capacity factor.

Non-Fuel Base Variable O&M ($/MWh)	$3.62[3]	$3.62	$3.62	$3.62	[EIA, 2007]
Base Fixed O&M ($/kW-yr)	$12.28[3]	$12.28	$12.28	$11.29 - 14.73[2]	[EIA, 2007]
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate (BTU/kWh)	10,807	10,807	10,807	10,807	[EIA, 2007]
Capacity factor (%)	5%	5%	5%	5%	[CEC 2007 Beta Model]

Notes:

[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%.

[2]Capital costs and fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20)

[3]Fixed and Variable O&M cost originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Levelized Costs

Table B shows reference case levelized costs for new CT generation in each of the 11 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A, along with financing costs during construction, and are calculated based on merchant financing assumptions. Table B also shows reference case fuel cost assumption ranging from $7.14 to $8.50 per million Btu across zones (see Fuel Cost Assumptions Report). The reference case range of busbar levelized cost of energy (LCOE) for CTs in the WECC is $77-91/MWh. Other costs associated with new CT generation in addition to busbar costs, for example the costs of transmission interconnection, are covered in separate reports.

Table B. Natural Gas CT Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$673**	**$12**		**5%**		**n/a**
AB	1.00	$673	$12	$7.15	5%	$409	n/a
AZ-S. NV	1.00	$673	$12	$8.29	5%	$421	n/a
BC	1.00	$673	$12	$7.35	5%	$411	n/a
CA	1.20	$807	$15	$8.46	5%	$489	n/a
CFE	1.00	$673	$12	$8.45	5%	$423	n/a
CO	0.97	$652	$12	$7.18	5%	$399	n/a
MT	1.02	$686	$13	$7.14	5%	$415	n/a
NM	0.96	$646	$12	$7.97	5%	$405	n/a
N. NV	1.09	$733	$13	$8.50	5%	$453	n/a
NW	1.11	$747	$14	$7.25	5%	$446	n/a
UT-S. ID	1.00	$673	$12	$7.31	5%	$410	n/a
WY	0.92	$619	$11	$7.14	5%	$382	n/a

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs (which is assumed not to vary by region) from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Benchmarking of CT Costs

Levelized Costs

As noted in Table B, the GHG calculator uses a busbar LCOE of $489 for a CCGT in California (2008$). Table C below compares the GHG Calculators busbar levelized cost for California to the latest levelized costs estimates (with merchant financing) from the CEC's Cost of Generation model, as reported by CEC staff (and adjusted here to 2008$). The fixed cost portion of the levelized cost estimate from CEC is lower than the CEC cost estimate.

Table C: LCOE Benchmarking Comparison (2008 $/MWh) – Merchant Financing

Source	GHG Calc (Busbar)	CEC COG
Plant	**160 MW Conventional (in CA)**	**100 MW Conventional**
Capital	$272.94	
Fixed O&M	40.48	
Taxes & Insurance	80.00	
Total Fixed	**$393.42**	**$512.99**
Fuel	91.47	
Variable O&M	3.62	
Total Variable	**$95.09**	**$114.74**
Total	**$488.51**	**$627.73**

Notes:
[1]All values shown in 2008$. CEC values have been adjusted from 2007$ to 2008$ using general inflation rate of 2.5%.
[2]CEC is currently updating its Cost of Generation model, and values shown here were provided by CEC staff as most recent estimates.
[3]The GHG Calculator values have been adjusted upward using the zonal multiplier for California (1.2), and represents a busbar cost estimate that does not include expenses for interconnection or emission allowances. See table D below

Capital Costs

Table D explores these differences in capital cost between the models. The CEC model's total includes interconnection costs and environmental permits that are not included in the GHG Calculator's busbar cost estimate. The GHG Calculator's installed cost estimate of $927 is in a near range to the base value from the CEC model of $966 when those other items are excluded.

Table D: Capital Cost Comparison (2008 $/kW) [1]

Component	GHG Calc (overnight)	GHG Calc (installed)	CEC COG (installed)
Base	$807[2]	$927	$966
Interconnection			35
Env. Permits			25
TOTAL			**$1025**

Notes:
[1]All values shown in 2008$. CEC values have been adjusted from 2007$ to 2008$ using general inflation rate of 2.5%.
[2]The GHG Calculator overnight cost is taken from Table B, and represents the EIA 2007 AEO value, adjusted for recent cost escalation and for the California regional cost multiplier of 1.2. The GHG Calculator installed cost represents the overnight cost multiplied by the financing during construction multiplier of 114.9% Both GHG Calculator costs represent cost at the busbar, and therefore do not include interconnection or permitting costs.

Capital Costs and Performance Characteristics

Table E below compares the GHG Calculator's reference plant costs and performance characteristics to those provided from other models. The plant used in the GHG Calculator is assumed to have the same capacity factor of the plant in the CEC model (5%). This value is in the same range as the estimate for peaking plants from the Northwest Power and

Conservation Council's (NWPPC) 5th Power Plan (10%). Cost and other data are included below for the GHG Calculator, the EIA AEO 2007 data (for Conventional and Advanced CTs), the 2004 MPR, the CEC COG model, and the NWPPC's estimates. All data have been converted to 2008$ for ease of comparison.

Table E: CT Assumptions Comparison –EIA, MPR, CEC, NWPCC (2008$)

Source	GHG Calc	EIA – Conv.	EIA – Adv.	2004 MPR	CEC COG	2004 NWPPC
Plant Description	160 MW CT	160 MW Conventional CT	230 MW Advanced CT	n/a	100 MW Conventional CT	(2 x 47 MW) Twin Aeroderivative Gas Turbines such as GE LM6000
Overnight Capital Cost $/kW	$807 (CA-specific plant)	$452	$422	$599		$731
Installed Capital Cost $/kW	$927 (CA-specific plant)				$966 (base) $1025 (incl. interconn. and env. permits)	
Capacity Factor	5%	30%	30%		5%	10% (for peaking service)
Fixed O&M ($/kW-yr)	$15 (CA-specific)	$12.28	$10.67		$7.31	$9.75
Variable O&M ($/MWh)	$3.62 (All zones)	$3.62	$3.21		$26.40	$9.75
Heat Rate (Btu/kWh)	10,807	10,807 (2006 order date)	9,166 (2006 order date)	9,662 (new plant)	9,266	New: • 9,900 Lifetime Average: • 9,960 Industrial Lifetime Average: • 10,500
Heat Rate Improvement		2003-2010: -0.23% 2003-2025: --0.20%	2003-2010: -0.54% 2003-2025: -0.22%	n/a	n/a	-0.5%/year (5% learning rate)
Technology Vintage Cost Change		2003-2010: -1.02% 2003-2025: 0%	2003-2010: -0.49% 2003-2025: 0%	n/a	n/a	-0.5%/year

[1]All values shown in 2008$. CEC values have been adjusted from 2007$ to 2008$ using general inflation rate of 2.5%. 2004 MPR values and EIA are adjusted from 2005$ to 2008$ at 2.5% per year. NWPCC values are adjusted from 2000$ to 2008$ at 2.5% per year.

Sources

California Air Resources Board, Draft California Greenhouse Emissions Inventory, August 2007.

California Energy Commission, “2006 Net System Power Report,” CEC-300-2007-007, CEC Staff Report, April 2007.

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23. New Conventional Coal Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Coal-fired generation owned by or under long-term contract to California utilities currently provides at least 6% of the electricity used to serve California loads, and as much as an additional 10% depending on the method used to assign generation to imports.[61] Within the WECC as a whole, coal generation constitutes roughly one-third of the total electricity supply.[62] Most coal-fired generation originates from large plants that run year-round to provide baseload power, burning pulverized coal to operate steam turbines. Coal is an abundant and inexpensive fuel in the Western U.S., with recent prices averaging around $2 per million Btu. At typical baseload plant efficiencies, the fuel cost component of generation is about 2 cents per kilowatt-hour, making it one of the most inexpensive technologies to operate.

Coal combustion is a major source of GHG emissions, with a typical value of 208 pounds of CO_2 emitted per million Btus of coal burned. Lifecycle GHG emissions from upstream and downstream processes such as plant construction, coal mining and transportation, and embedded energy in cooling water, are not included in the California emissions inventory. Within the WECC, coal-fired generation is currently responsible for about 75% of total sector emissions. Determining the coal emissions for which California loads are responsible is a difficult question that depends on the method used to assign generation to imports, but coal under known California ownership and long-term contracts produces at least about 30% of electricity sector emissions; in the latest draft California Emissions Inventory, coal generation is responsible for more than 60% of sector emission.[63] A 2006 California law, SB1386, forbids utilities from buying or signing contracts of longer than five years with new baseload coal plants. However, numerous new coal plants have been proposed elsewhere in the WECC.

Reference Case Resource, Cost, and Performance Assumptions

Table A gives the reference case resource, cost, and performance assumptions for new conventional coal generation used in the GHG calculator. The reference technology to which these assumptions apply is a new 600 MW supercritical plant using pulverized scrubbed coal.[64] These costs do not apply to coal IGCC or to coal IGCC with carbon capture and storage. The cost and performance of these technologies are detailed in a separate report.

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[61] The CEC 2006 Net System Power Report shows 17,573 GWh of specified coal generation, and 28,663 GWh of coal in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[62] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[63] For 2004, the most recent year included in draft inventory, coal contributed 63.3 million metric tons out of a total of 100.1 million metric tons of GHGs generated to serve California loads. (CARB 2007, calculation by author.)
[64] EIA AEO Assumptions 2007, Table 39.

The values in Table A are largely derived from the EIA's *Annual Energy Outlook 2007*, which is considered a relatively unbiased source for new technology cost and performance estimates. However, *AEO 2007* costs are generally too low, as they do not reflect recent capital cost increases resulting from higher materials costs and unfavorable exchange rates. The Table A reference case values are adjusted to reflect these increases.

The coal fuel resource is assumed to be unlimited. The base capital cost for new coal plants is $2066/kW, prior to applying zonal cost multipliers (see Table B) and prior to adjusting for financing costs during construction (see "Financing and Incentives" report). This value is based on the *AEO 2007* total overnight cost assumption, adjusted for inflation, recent increases in the cost of materials. Reference case non-fuel variable O&M costs are $4.65/MWh and fixed O&M costs are $27.90/kW-year.

The reference case performance values are a heat rate of 8,844 Btu/kWh and a capacity factor of 85%, which follow the *AEO 2007* assumptions. [65]

Table A. Coal Steam Turbine Cost, Resources, & Performance

	2008 value	2020 reference case value	2020 tech growth case	Range of 2008 values in model	Sources
Base generation capital cost ($/kW)	$2,066[1]	$2,066	$2,066	$1,901 - $2,479[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no net change]
AFUDC Multiplier (%)	133.3%	133.3%	133.3%	133.3%	[CEC Beta Model, 2007]
Variable O&M ($/MWh)	$4.65[3]	$4.65	$4.65	$4.65	[EIA, 2007]
Fixed O&M ($/kW-yr)	$27.90[3]	$27.90	$27.90	$25.67 - $33.48[2]	[EIA, 2007]
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in Rest-of-WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate	8,844	8,844	8,844	8,844	[EIA, 2007]

[65] The nominal capacity factor of 85% is only used for ranking of potential new resource additions based on levelized costs (see "Resource Ranking and Selection" report). In the GHG model, production costs depend on the dispatch of each generating unit in the production simulation, which may be very different from the nominal capacity factor.

(BTU/kWh)					
Capacity factor (%)	85%	85%	85%	85%	[EIA, 2007]

Notes:
[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%.
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20).
[3]Fixed and Variable O&M cost originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Busbar Levelized Costs

Table B shows reference case busbar levelized costs for new coal generation in each of the 12 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A, along with financing costs during construction, and are calculated based on merchant financing assumptions.. Table B also shows reference case fuel cost assumptions for each region, with a range for coal of $1.04 to $2.56 per million Btu (see "Fuel Cost Forecast" report). The reference case range of busbar levelized cost of energy (LCOE) for new coal generation in the WECC is $74-106/MWh. Other costs associated with new coal generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports.

Table B. Coal Steam Turbine Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$2,066**	**$28**		**85%**		**n/a**
AB	1.00	$2,066	$28	$2.56	85%	$93	n/a
AZ-S. NV	1.00	$2,066	$28	$2.15	85%	$89	n/a
BC	1.00	$2,066	$28	$2.56	85%	$93	n/a
CA	1.20	$2,479	$33	$2.56	85%	$106	n/a
CFE	1.00	$2,066	$28	$2.56	85%	$93	n/a
CO	0.97	$2,004	$27	$1.73	85%	$83	n/a
MT	1.02	$2,107	$28	$1.04	85%	$81	n/a
NM	0.96	$1,983	$27	$2.47	85%	$89	n/a
N. NV	1.09	$2,252	$30	$2.56	85%	$99	n/a
NW	1.11	$2,293	$31	$2.56	85%	$100	n/a
UT-S. ID	1.00	$2,066	$28	$1.86	85%	$87	n/a
WY	0.92	$1,901	$26	$1.09	85%	$74	n/a

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price

escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.

[4] Busbar levelized cost of energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, (d) tax liability and credits.

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24. New Coal IGCC Generation w/ & w/out CCS Resource, Cost, and Performance Assumptions

Current Status of Technology

Coal integrated gasification combined cycle (IGCC), and coal IGCC with carbon capture and storage (CCS), are new generating technologies that have the potential to reduce GHG emissions while continuing to permit the use of an abundant and inexpensive fuel. Coal IGCC generation has a very limited commercial track record, with only four demonstration units in commercial operation worldwide. The first U.S. IGCC demonstration power plant was in California in the 1980s, the Cool Water Project conducted by Southern California Edison in conjunction with GE and Texaco, but there are no current IGCC plants in operation in California. CCS has no track record at all in commercial operation, and faces significant technical challenges. The viability of long-term storage of CO_2 in geologic formations in particular remains a scientific and engineering challenge. Nonetheless, the attractiveness of these technologies is apparent when considered against the prospect of a new power generation fleet dominated by conventional coal.

Within the WECC as a whole, coal generation constitutes roughly one-third of the total electricity supply, while being responsible for about 75% of electricity sector GHG emissions.[66] Most coal-fired generation comes from large, baseload power plants that burn pulverized coal to operate steam turbines. Coal is an abundant and inexpensive fuel in the Western U.S., with recent prices averaging around $2 per million Btu. At typical baseload plant efficiencies, the fuel cost component of generation is about 2 cents per kilowatt-hour, making it one of the most inexpensive technologies to operate. Determining the coal emissions for which California loads are responsible is a difficult question that depends on the method used to assign generation to imports, but coal under known California ownership and long-term contracts produces at least about 30% of electricity sector emissions; in the latest draft California Emissions Inventory, coal generation is assigned responsibility for more than 60% of sector emission.[67] A 2006 California law, SB1386, forbids utilities from buying or signing contracts of longer than five years with new baseload conventional coal plants. Coal IGCC with CCS, however, would not be restricted by SB1368 as long as the storage method for CO_2 was deemed effective and verifiable.

In IGCC technology, a gasifier turns coal into a synthetic gas containing mostly hydrogen and carbon monoxide. This gas is then burned in a combustion turbine, and the waste heat recovered and used to operate a steam turbine. The "back end" of this configuration is a combined cycle gas turbine, very similar to the natural gas CCGTs now providing the largest share of California's generation. In IGCC with CCS, there is the possibility of either removing carbon from the synthetic gas to produce a gas that is mostly hydrogen, or of removing CO_2 after combustion. Most experts feel that pre-combustion carbon removal has the highest likelihood of commercial success. In either case, two waste streams remain, solid ash or slag from the gasification process that must be disposed of, and a carbon-rich gas that must be sequestered for the long term. Both technologies require significant amounts of

[66] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[67] For 2004, the most recent year included in draft inventory, coal contributed 63.3 million metric tons out of a total of 100.1 million metric tons of GHGs generated to serve California loads. (CARB 2007)

water for the gasification and carbon removal processes, and as cooling water for the CCGT component. Both of these issues would require considerable attention in order for coal IGCC technologies to be implemented on a large scale in water-limited California.

Reference Case Resource, Cost, and Performance Assumptions

Tables A1 and A2 give the reference case resource, cost, and performance assumptions used in the GHG calculator for new coal IGCC generation and coal IGCC with CCS, respectively. The reference technology to which these assumptions apply is a new 550 MW IGCC plant, with pre-combustion carbon removal in the case of CCS .[68]

The values in Tables A1 and A2 are largely derived from the EIA's *Annual Energy Outlook 2007*, which is considered a relatively unbiased source for new technology cost and performance estimates. However, *AEO 2007* costs are generally too low, as they do not reflect recent capital cost increases resulting from higher materials costs and unfavorable exchange rates. The reference case values are adjusted to reflect these increases.

The coal fuel resource is assumed to be unlimited. The base capital cost for new coal IGCC is $2388/kW, prior to applying zonal cost multipliers and financing costs during construction (see Table B1). This value is based on the *AEO 2007* total overnight cost assumption, adjusted for inflation, recent increases in the cost of materials. (See Financing Assumptions Report.) Reference case non-fuel variable O&M costs are $2.96/MWh and fixed O&M costs are $39.16/kW-year.

The base overnight capital cost for new coal IGCC with CCS is $3418/kW, with the same adjustments as described above for coal IGCC. Reference case non-fuel variable O&M costs for coal IGCC with CCS are $4.50/MWh and fixed O&M costs are $46.11/kW-year.

The reference case performance values for coal IGCC is a heat rate of 8,309 Btu/kWh. For coal IGCC with CCS, the heat rate is 9,713 Btu/kWh. For both technologies, the reference case capacity factor is 85%, which follows the *AEO 2007* assumptions. [69]

Table A1. Coal IGCC Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources

[68] EIA AEO Assumptions 2007, Table 39.

[69] The nominal capacity factor of 85% is only used for ranking of potential new resource additions based on levelized costs (see "Resource Ranking and Selection" report). In the GHG model, production costs depend on the dispatch of each generating unit in the production simulation, which may be very different from the nominal capacity factor.

Base overnight capital cost ($/kW)	$2,388[1]	$2,388	$2,388	$2,197 - $2,866[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no net change]
AFUDC Multiplier (%)	133.3%	133.3%	133.3%	133.3%	[CEC Beta Model, 2007]
Variable O&M ($/MWh)	$2.96[3]	$2.96	$2.96	$2.96	[EIA, 2007]
Fixed O&M ($/kW-yr)	$39.16[3]	$39.16	$39.16	$36.02 - $46.99[2]	[EIA, 2007]
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in Rest-of-WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate (BTU/kWh)	8,309	8,309	8,309	8,309	[EIA, 2007]
Capacity factor (%)	85%	85%	85%	85%	[EIA, 2007]

Notes:
[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%.
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20).
[3]Fixed and Variable O&M cost originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Table A2. Coal IGCC w/ CCS Cost, Resources, & Performance

	2008 value	2020 reference case value (in 2008$)	2020 tech growth case	Range of 2008 values in model	Sources
Base overnight capital cost ($/kW)	$3,418[1]	$3,418	$3,418	$3,144 - $4,101[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no net change]
AFUDC Multiplier (%)	150%	150%	150%	150%	[CEC 2007 Beta Model; Assumed value higher than other conventionals in

					model due to longer expected construction time.]
Variable O&M ($/MWh)	$4.50[3]	$4.50	$4.50	$4.50	[EIA, 2007]
Fixed O&M ($/kW-yr)	$46.11[3]	$46.11	$46.11	$42.42 - $55.33[2]	[EIA, 2007]
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in Rest-of-WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate (BTU/kWh)	9,713	9,713	9,713	9,713	[EIA, 2007]
Capacity factor (%)	85%	85%	85%	85%	[EIA, 2007]

Notes:
[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%.
[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20).
[3]Fixed and Variable O&M cost originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Levelized Costs

Tables B1 and B2 show reference case busbar levelized costs for new coal IGCC and new coal IGCC with CCS in each of the 11 WECC zones used in the GHG calculator. These values are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A. Tables B1 and B2 also shows reference case fuel cost assumptions for each region, with a range for coal of $1.04 to $2.56 per million Btu (see Fuel Cost Assumptions Report). With the performance described earlier and merchant financing assumptions (see Financing Assumptions Report), the resulting reference case range of levelized cost of energy (LCOE) for coal IGCC in the WECC is $83-116/MWh, and for IGCC with CCS is $125-173/MWh. Other costs associated with coal IGCC generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports.

Table B1. Coal IGCC Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$2,388**	**$39**		**85%**		**n/a**
AB	1.00	$2,388	$39	$2.56	85%	$101	n/a
AZ-S. NV	1.00	$2,388	$39	$2.15	85%	$98	n/a
BC	1.00	$2,388	$39	$2.56	85%	$101	n/a
CA	1.20	$2,866	$47	$2.56	85%	$116	n/a
CFE	1.00	$2,388	$39	$2.56	85%	$101	n/a
CO	0.97	$2,316	$38	$1.73	85%	$92	n/a
MT	1.02	$2,436	$40	$1.04	85%	$90	n/a
NM	0.96	$2,292	$38	$2.47	85%	$97	n/a
N. NV	1.09	$2,603	$43	$2.56	85%	$108	n/a
NW	1.11	$2,651	$43	$2.56	85%	$109	n/a
UT-S. ID	1.00	$2,388	$39	$1.86	85%	$95	n/a
WY	0.92	$2,197	$36	$1.09	85%	$83	n/a

[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Table B2. Coal IGCC w/ CCS Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$3,418**	**$46**		**85%**		**n/a**
AB	1.00	$3,418	$46	$2.56	85%	$149	n/a
AZ-S. NV	1.00	$3,418	$46	$2.15	85%	$145	n/a
BC	1.00	$3,418	$46	$2.56	85%	$149	n/a
CA	1.20	$4,101	$55	$2.56	85%	$173	n/a
CFE	1.00	$3,418	$46	$2.56	85%	$149	n/a
CO	0.97	$3,315	$45	$1.73	85%	$138	n/a
MT	1.02	$3,486	$47	$1.04	85%	$137	n/a
NM	0.96	$3,281	$44	$2.47	85%	$144	n/a
N. NV	1.09	$3,725	$50	$2.56	85%	$160	n/a
NW	1.11	$3,794	$51	$2.56	85%	$162	n/a
UT-S. ID	1.00	$3,418	$46	$1.86	85%	$143	n/a
WY	0.92	$3,144	$42	$1.09	85%	$125	n/a

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price

escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

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25. New Nuclear Generation Resource, Cost, and Performance Assumptions

Current Status of Technology

Nuclear generation from plants owned by or under long-term contract to California utilities currently provides 11% of the electricity used to serve California loads, with an additional 2% of generation from nuclear plants depending on the method used to assign generation to imports.[70] Within the WECC as a whole, nuclear generation constitutes about 8% of the total electricity supply.[71] All nuclear generation originates from large plants that run year-round providing baseload power, using heat from the fission of enriched uranium fuel to operate steam turbines.

Nuclear generation does not produce significant GHG emissions. Lifecycle GHG emissions from upstream and downstream processes such as construction, mining, fuel preparation, embedded energy in cooling water, and spent fuel storage and processing are not included in the California emissions inventory, and so the emissions intensity of nuclear generation is zero.[72] A 1985 California law prohibits the construction of new nuclear generating plants in California until such time as the state determines that the nuclear waste storage problem is solved. The two in-state nuclear generating stations, PG&E's Diablo Canyon and SCE's San Onofre, are permitted to continue to operate until retired; currently, however, they do face new environmental requirements associated with cooling water use (see Plant Retirements and Repowering Report). New nuclear plants have been discussed elsewhere in the WECC, but currently no new nuclear plant license applications for locations in the WECC have been received by the federal Nuclear Regulatory Commission.

Reference Case Resource, Cost, and Performance Assumptions

Table A gives the reference case resource, cost, and performance assumptions for new nuclear generation used in the GHG calculator. The reference technology to which these assumptions apply is a new 1350 MW light water reactor (LWR) using enriched uranium fuel.[73] These costs do not apply to so-called "fourth generation" nuclear technologies such as high-temperature gas reactors (HTGR) or to breeder reactors, which are not included as options in the GHG calculator. Nuclear fusion reactors are also not included.

The values in Table A are largely derived from the EIA's *Annual Energy Outlook 2007*, which is considered a relatively unbiased source for new technology cost and performance estimates. However, *AEO 2007* costs are generally too low, as they do not reflect recent capital cost increases resulting from higher materials costs and unfavorable exchange rates. The Table A reference case values are adjusted to reflect these increases.

[70] The CEC 2006 Net System Power Report shows 31,959 GWh of specified coal generation, and 6,191 GWh of coal in unspecified imports, out of a total gross system power of 294,865 GWh in 2006.
[71] CEC 2007 IEPR Scenarios, 2009 Scorecard.
[72] CARB 2007.
[73] EIA AEO Assumptions 2007, Table 39.

The nuclear fuel resource is assumed to be unlimited. The base capital cost for new nuclear plants is $3333/kW, prior to applying zonal cost multipliers (see Table B) and prior to adjusting for financing costs during construction (see "Financing and Incentives" report). This value is based on the *AEO 2007* total overnight cost assumption, adjusted for inflation and recent increases in the cost of materials. Reference case non-fuel variable O&M costs are $0.51/MWh and fixed O&M costs are $68.79/kW-year. The reference case performance values are a heat rate of 10,400 Btu/kWh and a capacity factor of 85%, which follow the *AEO 2007* assumptions.

Table A. Nuclear Cost, Resources, & Performance

	2008 value	2020 reference case value	2020 tech growth case	Range of 2008 values in model	Sources
Base generation capital cost ($/kW)	$3,333[1]	$3,333	$3,333	$3,066 - $3,999[2]	Reference case: [EIA, 2007] Tech growth case: [Assumed no net change]
AFUDC Multiplier (%)	150%	150%	150%	150%	[CEC 2007 Beta Model, adjusted for 6 year lead time compared to 4 for coal]
Variable O&M ($/MWh)	$0.51[3]	$0.51	$0.51	$0.51	[EIA, 2007]
Fixed O&M ($/kW-yr)	$68.79[3]	$68.79	$68.79	$63.29 - $82.55[2]	[EIA, 2007]
Gross resource in WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in CA (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Filtered resource in Rest-of-WECC (MW)	No limit applicable.	No limit applicable.	No limit applicable.	No limit applicable.	[n/a]
Nominal Heat Rate (BTU/kWh)	10,400	10,400	10,400	10,400	[EIA, 2007]
Capacity factor (%)	85%	85%	85%	85%	[EIA, 2007]

Notes:
[1]Base value originally reported in 2005$ in EIA AEO 2007. Cost has been adjusted (a) from 2005$ to 2007$ at rate of 25% per year to account for recent price escalation, and (b) from 2007$ to 2008$ at general inflation rate of 2.5%.

[2]Capital costs and Fixed O&M costs in model vary by region, based on state-specific factors from US Army Corps of Engineers, Civil Works Construction Cost Index System (CWCCIS), March 2007. Lowest multiplier for region in WECC is WY (0.92); highest multiplier is CA (1.20)
[3]Fixed and Variable O&M cost originally reported by EIA in 2005$. Costs have been adjusted from 2005$ to 2008$ at general inflation rate of 2.5%.

Zonal Levelized Costs

Table B shows reference case busbar levelized costs for new nuclear generation in each of the 12 WECC zones used in the GHG calculator. They are derived by applying zonal cost multipliers from the U.S. Army Corps of Engineers to the base generation and O&M costs in Table A, along with financing costs during construction, and are calculated based on merchant financing assumptions.. Table B also shows the reference case fuel cost assumption of $1.01 per million Btu, with no zonal variation (see Fuel Cost Assumptions Report). The reference case range of levelized cost of energy (LCOE) for nuclear power in the WECC is $122-156/MWh. Other costs associated with new nuclear generation in addition to busbar costs, for example the costs of transmission interconnection and long-distance transmission, are covered in separate reports

Table B. Nuclear Busbar Levelized Cost by Zone

Resource Zone	Zonal Cost Multiplier	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Fuel Cost ($/MMBTU)	Capacity Factor Range	Busbar LCOE Range ($/MWH)	Net Resource Potential (MW)
Base Value	**1.00**	**$3,333**	**$69**		**85%**		**n/a**
AB	1.00	$3,333	$69	$1.01	85%	$132	n/a
AZ-S. NV	1.00	$3,333	$69	$1.01	85%	$132	n/a
BC	1.00	$3,333	$69	$1.01	85%	$132	n/a
CA	1.20	$3,999	$83	$1.01	85%	$156	n/a
CFE	1.00	n/a	n/a	$1.01	n/a	n/a	-
CO	0.97	$3,233	$67	$1.01	85%	$128	n/a
MT	1.02	$3,400	$70	$1.01	85%	$134	n/a
NM	0.96	$3,200	$66	$1.01	85%	$127	n/a
N. NV	1.09	$3,633	$75	$1.01	85%	$143	n/a
NW	1.11	$3,699	$76	$1.01	85%	$145	n/a
UT-S. ID	1.00	$3,333	$69	$1.01	85%	$132	n/a
WY	0.92	$3,066	$63	$1.01	85%	$122	n/a

Notes:
[1]All values shown in 2008$.
[2]Capital Cost and Fixed O&M Cost by zone are calculated by multiplying base value for cost by the zonal cost multiplier.
[3]Fuel costs are for 2020, and shown in 2008$. Data from 2005 SSG-WI database, and have been inflated (a) from 2005$ to 2008$ at general inflation rate of 2.5%, and (b) from 2005 to 2020 at an annual fuel price escalation rate of 3% real. For resource zones containing multiple SSG-WI regions, fuel costs are have been averaged.
[4]Busbar levelized Cost of Energy (LCOE) is calculated using cost and performance data from this table, as well as: (a) financing during construction cost multiplier and non-fuel variable O&M costs from preceding table, (b) insurance of 0.5% of capital cost, (c) property tax of 1% of capital cost, and (d) income tax liability.

Sources

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26. Renewable Supply Curves

Supply Curves by WECC Zone

The resource availability and levelized costs for renewable energy in each of the 11 WECC zones represented in the GHG model is illustrated by supply curves.[74] These supply curves show the levelized cost of generation ($/MWh) at different levels of resource availability (GWh) within each zone.

The development of reference case assumptions regarding resource availability, cost, and performance is discussed in individual reports on each of the renewable technologies: wind, concentrating solar power (CSP), biomass, geothermal, and small hydro. The levelized costs for all of these technologies, plus those of conventional technologies (coal, nuclear, natural gas, and conventional hydro) in the GHG calculator are summarized in the report "New Generation Resources, Costs, and Performance Summary."

A representative sample of the GHG calculator supply curves is provided below. Note that the supply curves include the cost of generation and transmission interconnection, but do not include the cost of long distance transmission, where that is required to gain access to new resource zones.

Figures 1 and 2 shows supply curves for renewable generation in California. Figure 1 shows the curves for the individual resource types, while Figure 2 shows the combined supply curve for all types. For illustrative purposes, dotted lines representing the estimated amount of renewable generation that must be procured to meet Renewable Portfolio Standard targets of 20% and 33% (on a total state load basis) are shown.

Figures 3 and 4 show supply curves for renewable in the WECC as a whole. Figure 3 shows the curves for the individual resource types, while Figure 4 shows the combined renewable supply curve for the WECC, with dotted lines illustrating the amount that would be required to meet a WECC-wide average RPS of 15% and 25%.

Figures 5 and 6 show the combined renewable generation supply curves for several WECC zones, with dotted lines showing the presumed RPS requirements for each zone. Figure 5 shows the supply curves for California, Arizona, Colorado, and the Northwest (Oregon and Washington), which are states with limited amounts of relatively inexpensive renewable resources when compared to presumed RPS requirements. Figure 6 shows the supply curves for Wyoming, Montana, New Mexico, Nevada, and British Columbia, which are states/provinces with large amounts of relatively inexpensive renewable resources when compared to presumed RPS requirements.[75]

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[74] Biogas and biomass are combined in all of the supply curves.

[75] Note: Costs may change in later versions of the GHG model. These curves should be considered illustrative.

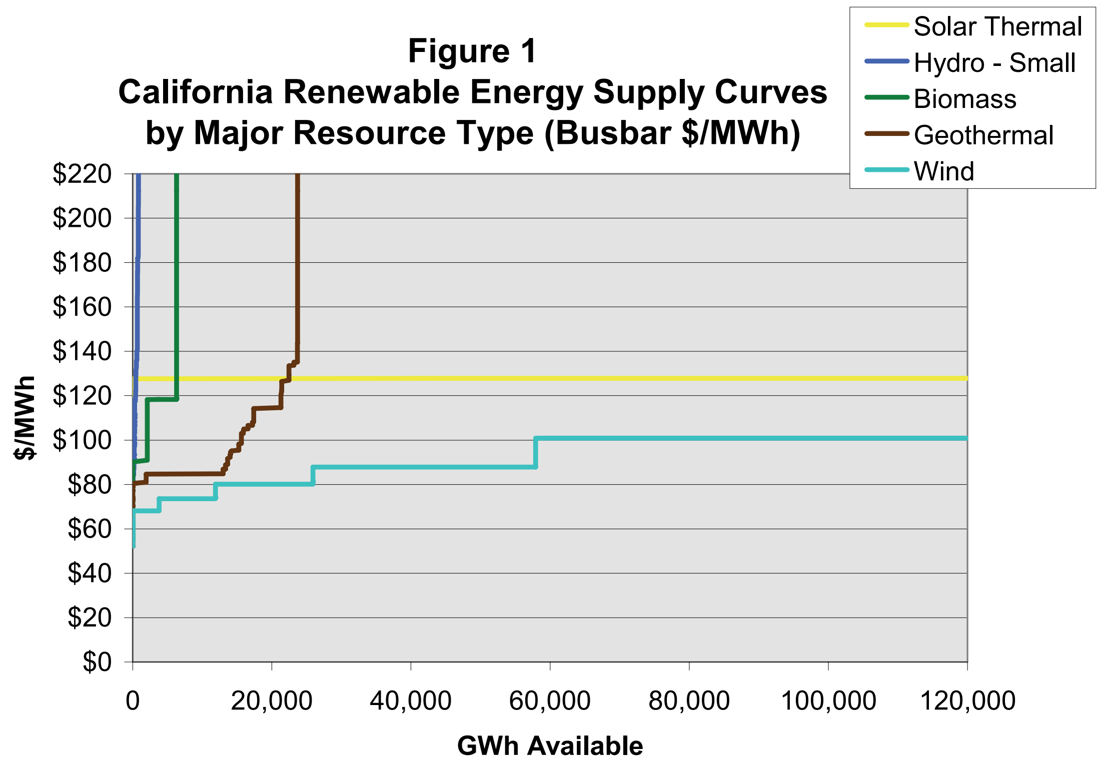


Figure 1
California Renewable Energy Supply Curves by Major Resource Type (Busbar $/MWh)

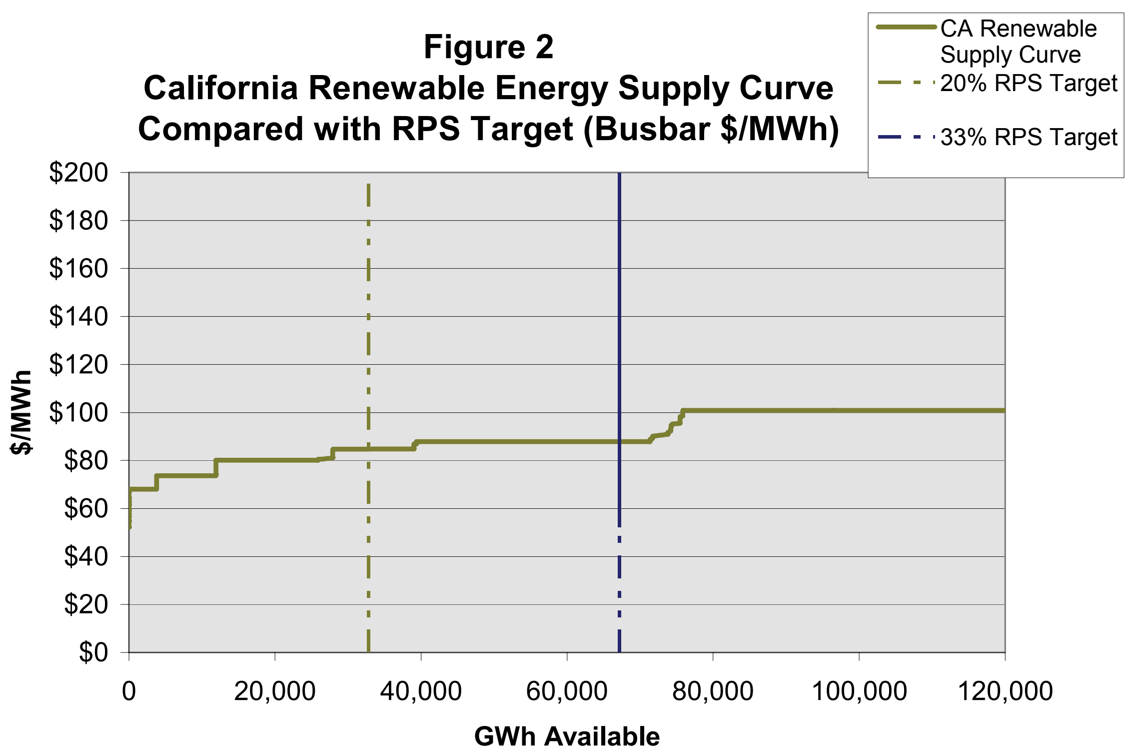


Figure 2
California Renewable Energy Supply Curve Compared with RPS Target (Busbar $/MWh)

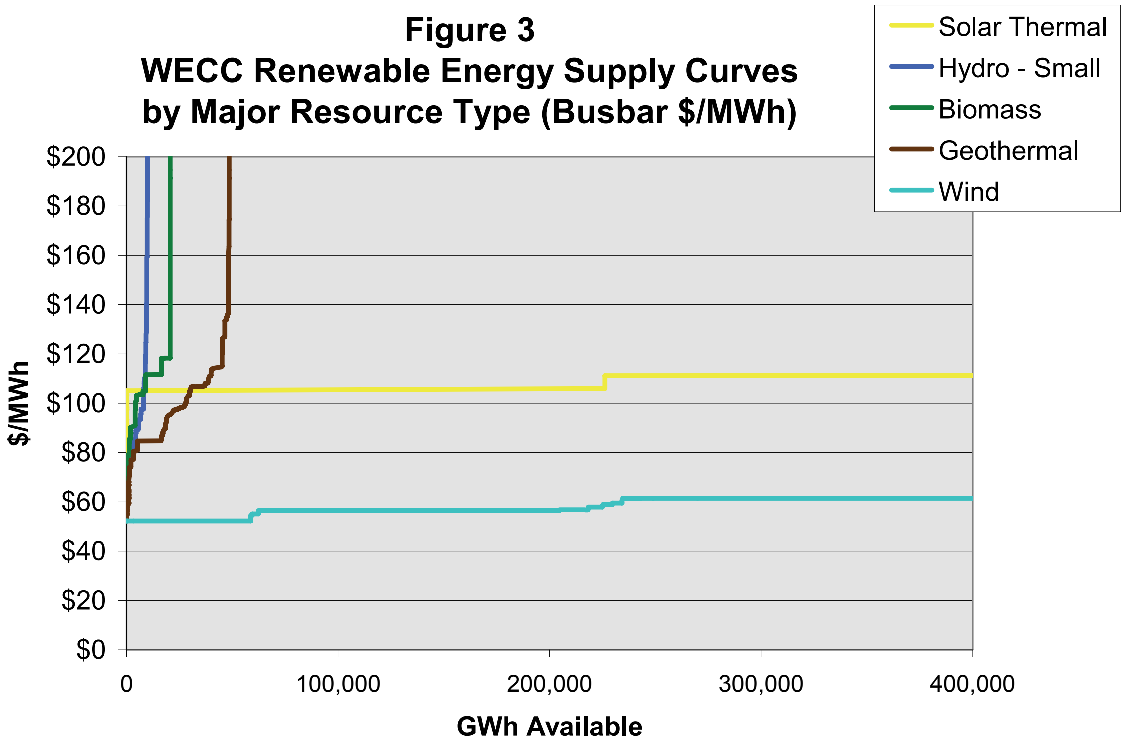


Figure 3
WECC Renewable Energy Supply Curves
by Major Resource Type (Busbar $/MWh)
Solar Thermal
Hydro - Small
Biomass
Geothermal
Wind
$/MWh
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
100,000
200,000
300,000
400,000
GWh Available

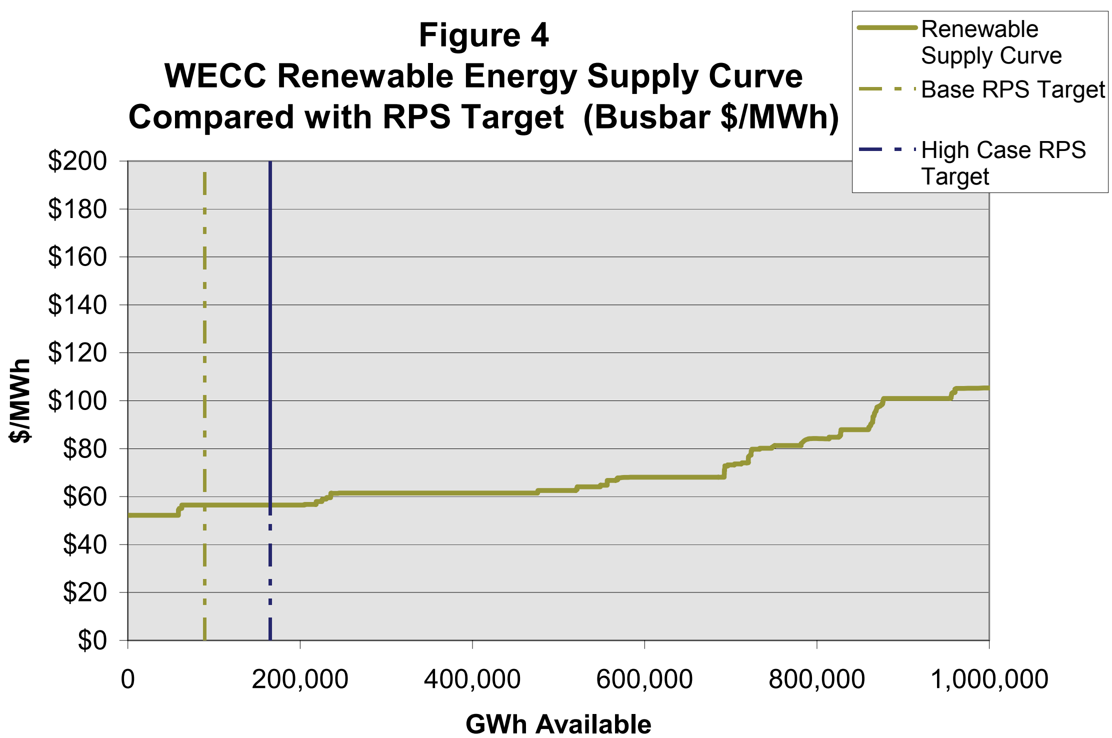


Figure 4
WECC Renewable Energy Supply Curve
Compared with RPS Target (Busbar $/MWh)
Renewable Supply Curve
Base RPS Target
High Case RPS Target
$/MWh
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
200,000
400,000
600,000
800,000
1,000,000
GWh Available

Figure 5. Renewable Energy Supply Curves for Major Consuming Regions, Compared with Base Case RPS Targets (Busbar $/MWh)

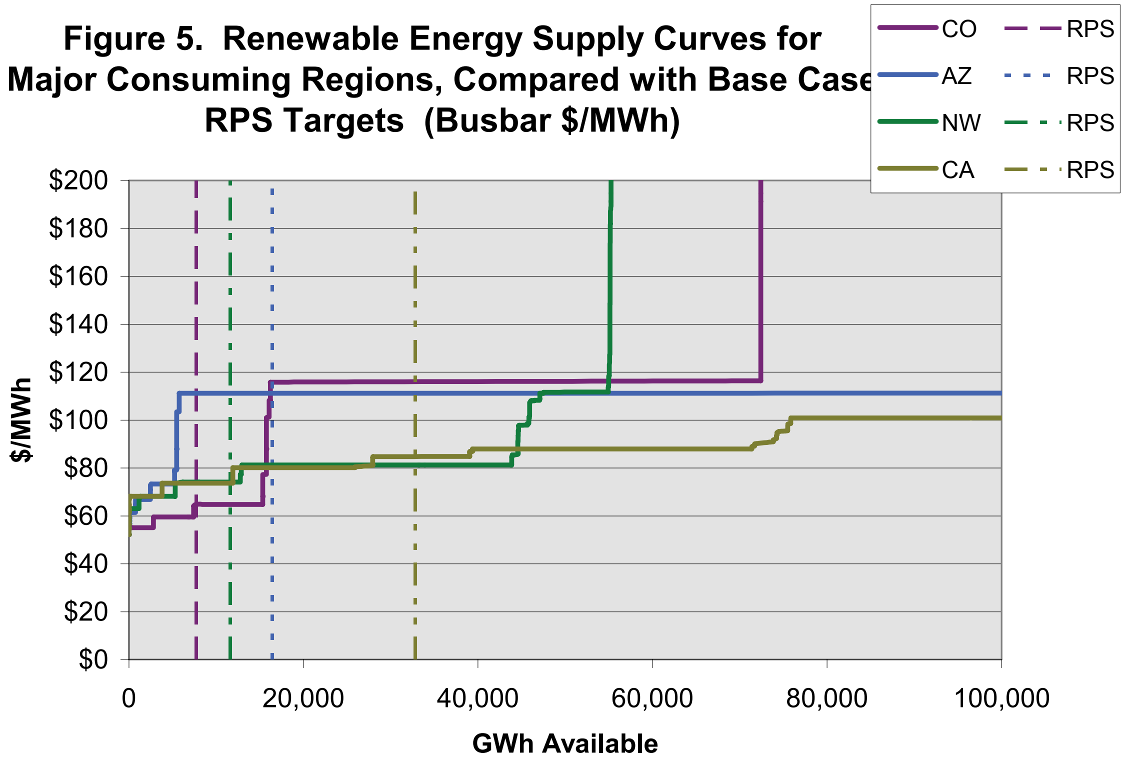
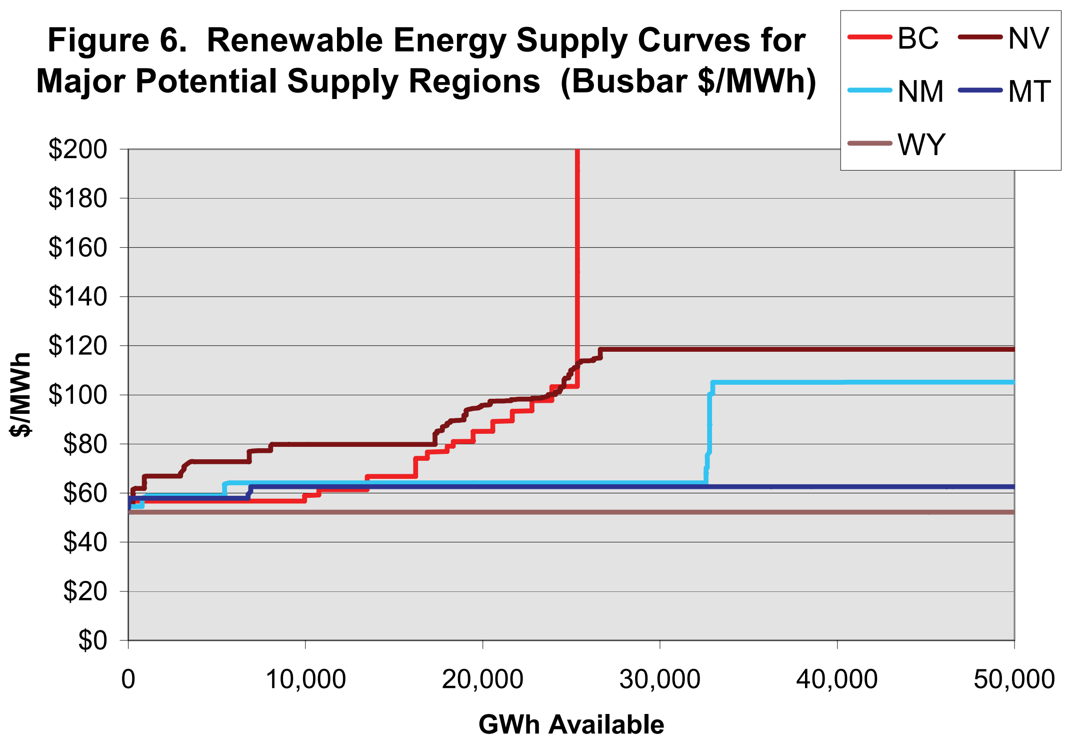


Figure 6. Renewable Energy Supply Curves for Major Potential Supply Regions (Busbar $/MWh)



27. Transmission Cost Assumptions

Transmission Costs in the GHG Model

Transmission upgrades can be a significant contributor to the cost of new generation, especially for resources that are in remote or transmission-constrained locations. The GHG model includes two different components of transmission upgrade cost:

(1) The costs of generation interconnection or "collector systems" – transmission that is radial to the main transmission grid and that collects energy produced by generators and transmits it to a higher voltage, backbone facility

(2) The costs of main grid upgrades or "trunk lines" – the higher voltage facilities necessary for transmitting large amounts of power over long distances.

The GHG model assumes that generation interconnection facilities are financed by the generation owner, while main grid upgrades are network upgrades that use investor-owned utility financing.

New studies of potential transmission upgrades to facilitate the development of low-carbon generation resources are outside the scope of the GHG modeling project, so transmission costs for both trunk lines and collector systems were developed on the basis of previous studies and accepted engineering-economic rules of thumb. However, the methodology for estimating the cost of transmission upgrades is currently under review to ensure that consistency with other costing methodologies used in the GHG model, and particularly to ensure that transmission costs reflect the recent, dramatic inflation in the cost of steel and other raw materials.

For transmission within California, assumptions about costs and potential routes and capacities are discussed in the next section. For interstate transmission WECC regions, including California, the assumptions are discussed in the subsequent section.

Transmission within California for Renewable Resources

In the GHG model reference cases, it is assumed that renewable resources will be obtained within California (and closely bordering areas such as northern Baja California (CFE) and the Reno, Nevada area) only, and that trunk lines to obtain renewable resources from distant regions are not built. The main assumptions regarding the transmission routes, line capacities, and costs necessary to provide access to the resources in different renewable resource zones within the state are shown in Table 1 below. (The development of zonal resource supply curves for new generation within these zones is discussed in the section on "Resource Ranking and Selection.")

The basis for cost estimation is shown in the "Cost Notes" column of Table 1. In many cases, costs are based on existing transmission studies, adjusted for inflation. In a few cases, costs are based on measured distances between resource zones and load centers, to which rule of thumb estimates were applied. These rules of thumb are shown in Table 2 and Table 3.

Table 1. California Transmission in the Reference Case

Cluster Name	Counties	Interconnection Point	Delivery Point	Total Cost ($MM 2008)	Cost Notes
Northeast CA	Siskiyou, Shasta, Modoc, Lassen	Geothermal and Wind Sites in Shasta, Lassen, Modoc, and Siskiyou Counties	Round Mountain & Cottonwood Substations in Shasta County	$263	Source: CRS, p.66, for 295 MW geothermal for geothermal (adjusted to 2008$). Added (3 x $1.1M/mile for 230 kV x 50 miles) + (3 x 2 x 10M each for line terminations) for interconnection of wind ~700 MW.
Geysers/Lake	Lake, Colusa, Sonoma	Geothermal and Wind sites in Lake & Colusa Counties (and on Sonoma Border with Lake County)	Vaca-Dixon Substation	$58	Assumed Upgrade of Geysers to Vaca-Dixon, per North Geysers transmission upgrade environmental study. Distance: 30 mi. Cost = ($1,600/MW-mi X 400 MW X 30 mi). Added ($1,600/MW-mi X 300 MW X 50 mi) for wind interconnection.
Bay Delta	Solano, Alameda, Contra Costa, Marin	Solano and Alameda Wind Sites	Vaca-Dixon Substation & Altamont Substation	$218	Source: CRS, p.66 (adjusted to 2008$).
Tehachapi	Kern	Tehachapi Wind Sites	Pardee/Vincent	$2,282	Source CRS, p.65 (adjusted to 2008$).
San Bernardino	San Bernardino	Mountain Pass & 2 new substations along the way	Lugo	$1,718	Assumed two 500 kV AC transmission lines with a length of 200 miles. Cost = (200 miles X $2.15 million per mile X 2 circuits) + (4 line terminations, series capacitor banks and svc x (26M+10M+30M) Plus 3 collection subs x 4 spokes per sub of 230 kV line,
Mono/Inyo	Mono, Inyo	Lundy/Mono/Lee Vining	Lugo	$432	CPUC 2003 Transmission Study for picking up 580 MW of Solar Thermal, Wind, Geothermal from Mono/San Bernardino total (removed costs for lines & substation going west to El Dorado)
San Diego	San Diego	East San Diego wind sites	San Diego (SWPL Substation)	$191	Source: CPUC Transmission Study 2003, p.90 (Adjusted to 2008$). Value has been doubled to account for doubling the capacity.
Imperial	Imperial	Imperial	San Diego	$1,269	Source CRS, p.65 (adjusted to 2008). Plus $44.2MM for Path 42 upgarde -- Source: SDG&E 10/30/2006 IV Bank 82 Addition Presentation, recommended option.

CA - Distributed	Entire State	Biomass/Biogas sites	Local regions throughout CA	$61	Assumed interconnection for 36 x 25 MW biomass units in urban area with 10 miles average gen tie. Cost = ($1,600/MW-mi X 25 MW X 3 miles X 36 units) + ($1.5 million substation upgrade X 36 units).
CFE	Northern Baja	Rumorosa/Mexicali	Around Miguel Substation	$1,269	Assumed same cost as Sunrise line
Reno Area/Dixie Valley	All NV Geo sites	Various Reno & Dixie Corridor Sites	(a) Bordertown, NV up to Malin Sub then down to Tracy Sub [1200 MW] plus (b) Donner Pass to Truckee [500 MW]& (b) PDCI tap near Gerlach, NV [400MW]	$1,169	Source: CRS, p.66 (adjusted to 2008$). Assume the existing DC line can accommodate with a new DC Substation and some upgrades; Assumes both new AC and PDCI tap in. Added costs from Geothermex report for collector to each of the sites.

Notes:
CRS = Center for Resource Solutions, *Achieving a 33% Renewable Energy Target*, prepared for CPUC, November 2005
CPUC Transmission Study 2003 = CPUC Energy Division, *Electric Transmission Plan for Renewable Resources in California*, December 2003

Table 2. Rules of Thumb for Transmission Capacity Estimates – California-Only Case

Approximate Power Carrying Capability of Uncompensated AC Transmission Lines (MW)

Nominal Voltage (kV) → Line Length (Miles) ↓	*138*	*161*	*230*	*345*	*500*	*765*
50	**145**	**195**	**390**	**1260**	**3040**	**6820**
100	**100**	**130**	**265**	**860**	**2080**	**4660**
200	**60**	**85**	**170**	**545**	**1320**	**2950**
300	**50**	**65**	**130**	**420**	**1010**	**2270**
400	**NA**	**NA**	**105**	**335**	**810**	**1820**
500	**NA**	**NA**	**NA**	**280**	**680**	**1520**
600	**NA**	**NA**	**NA**	**250**	**600**	**1340**

Source: Russell and Craft, *The Wheeling and Transmission Manual*, 3rd Edition, Spectrum Books, 1999.

Table 3. Rules of Thumb for Transmission Cost Estimates – California-Only Case

Table 4-3: Unit Costs Used in Developing Preliminary Transmission Cost Estimates (Millions of $2007)

Transmission Line Element	500-kV Facilities [20]	345-kV Facilities [21]	230-kV Facilities
Transmission Lines ($/Mile)			
- In California	2.15	n/a	1.1
- In Rest-of-WECC	1.75	1.6	0.65
Line Terminations (Each)($M) [22]	26	12	10
Series Capacitor Banks (Each)($M) [23]	10	6	n/a
SVCs (Each)($M) [24]	30	17	n/a

Source: CEC, Scenario Analysis for 2007 IEPR, Table 4-3.

Trunk Line Transmission Costs between WECC Regions

The methodology for estimating trunk line transmission costs from other WECC regions to California is still under development.

Generation Interconnection Costs

The GHG model contains six types of conventional resources and five types of renewable resources. Costs for generation interconnection – transmission facilities that connect the generator radially to the high-voltage, "backbone" grid – are estimated separately for each type of resource. Each resource is assigned a distance from the backbone grid, and is assessed the cost of building transmission over that distance. Interconnection costs are assumed to be linear with the size of the generation resource, and a simple rule of $1600/MW-mile is applied. Interconnection costs are also subject to the regional capital cost multiplier.

Assumptions about distance to the backbone grid vary by resource type. For renewable resources outside of California, the methodology for assigning transmission distances is integral to the methodology for assessing resource availability, about which more details can be found in the separate "Resource and Cost Assumptions" report for each technology.

Conventional

The model assumes the following distances to the backbone transmission system for conventional resources:

- Nuclear and coal resources: 25 miles

- CCGT and SCGT resources: 10 miles

Levelized interconnection costs for conventional resources range from $0.22 to $0.77/MWh.

Wind

For wind resources, the GHG model uses the NREL transmission assignment method to estimate collection costs for wind generation. This method estimates the total MW capacity of all existing 69kV to 345 kV lines in each WECC zone based on the line's length and voltage, and assumes that 10% of the total capacity of each line is available for transmission of new wind resources.[76] Starting with the lowest cost wind resources, the NREL optimization assigns wind resources of each wind class from individual grid squares to the nearest transmission line until no available transmission capacity remains, then moves to next nearest line. In the GHG model, the distances from the resource grid squares to transmission were backed out from the NREL data, and used to estimate the interconnection cost. In a few situations in which wind resources of Class 5 or higher were not assigned to a transmission line through the NREL methodology, E3 manually assigned the resource the highest transmission distance for any wind of the same region and class that did connect to available existing transmission.

Concentrating Solar Power

The GHG model uses NREL zonal data for solar thermal resources to estimate transmission interconnection costs for CSP. E3 used a web-based map from Idaho National Laboratory to measure the distance from the center of the greatest resource concentration within each NREL zone to the nearest transmission line with a voltage of 230 kV or higher.

Geothermal

In the GHG model, geothermal resources are identified on a site-specific basis. E3 used the INL map to locate transmission lines and measure the distance from the site location to the nearest transmission line with a voltage of 115 kV or higher.

Small Hydro

In the GHG model, small hydro resources are identified on a site-specific basis. E3 used the INL database and map to estimate the distance from potential hydro sites to transmission, then used this to determine the average distance from the site location to the nearest transmission line for all potential sites within each zone. Sites without specified distances were assigned the maximum value of 25 miles when calculating the zonal averages.

[76] Per NREL WinDS model description (http://www.nrel.gov/analysis/winds/transmission_cost.html), "The transmission line capacity as a function of kV rating and length is drawn from Weiss, Larry and S. Spiewak, 1998, The Wheeling and Transmission Manual, The Fairmont Press Inc., Lilburn GA."

Biomass

Biomass was treated as distributed resource, with average interconnection distance of 25 miles.

28. Cost of Integrating Wind Resources

Introduction

Wind resources are intermittent and variable in nature. The output of a wind turbine fluctuates from hour to hour, and even from minute to minute, depending on the speed of the wind at the turbine site. This imposes a cost on the electricity system, because the output of other generators must be varied in response to the fluctuations in wind output in order to maintain system frequency within acceptable levels. This cost is very small when wind generators make up only a fraction of the total generation in a control area, and the variations can be compensated for by very small changes in the output of generators that are already on line. However, the costs grow as more and more wind generators are added, and can become substantial at high levels of wind penetration, particularly if the presence of wind generators requires that operation of generators that would otherwise be offline. In an extreme case, integrating new wind resources could require the construction of new generators with the ability to quickly vary their output levels (so called "fast-ramping" capability). This paper describes E3's methodology for calculating the cost of integrating wind energy resources into electricity systems in California and other regions in the WECC. This paper addresses only the variable costs of accommodating the fluctuating output of wind resources. The cost of capacity required to serve peak loads is addressed in the paper entitled "Ensuring Load-Resource Balance."

Methodology

The cost of integrating large quantities of wind energy into an electricity system is unknown. Wind energy currently provides only 2% of California's electricity generation. However, the GHG Calculator must consider scenarios in wind energy which provides varying levels of California's electricity generation, up to and perhaps exceeding 10%. In order to develop an estimate of wind integration costs that is valid across a broad range of potential wind penetration levels, E3 researched ten studies of wind integration costs that specify levels of wind energy penetration for North American utilities. These studies were conducted by or on behalf of: Avista, the Bonneville Power Administration, Great River Energy, Idaho Power, Manitoba Hydro, the Minnesota Public Utilities Commission, PacifiCorp, Public Service of Colorado, Puget Sound Energy, We Energies, and Xcel Energy (Minnesota). References to the study documents are provided below.

Combined, the studies provided a sample of 32 estimates of integration costs for wind resource penetrations between 5% and 30% of total system generation capacity. E3 conducted a regression analysis on these 32 data points and developed a simple model of wind integration costs as a function of wind's share of total generation capacity. The resulting curve, and the original data points, are depicted in Figure 1 below. A regression model without an intercept achieves an R-square value of 0.79. The regression coefficient indicates that for each percentage point of wind energy penetration, (expressed as wind's share of total nameplate capacity in the control area), wind integration will cost \$0.3128.

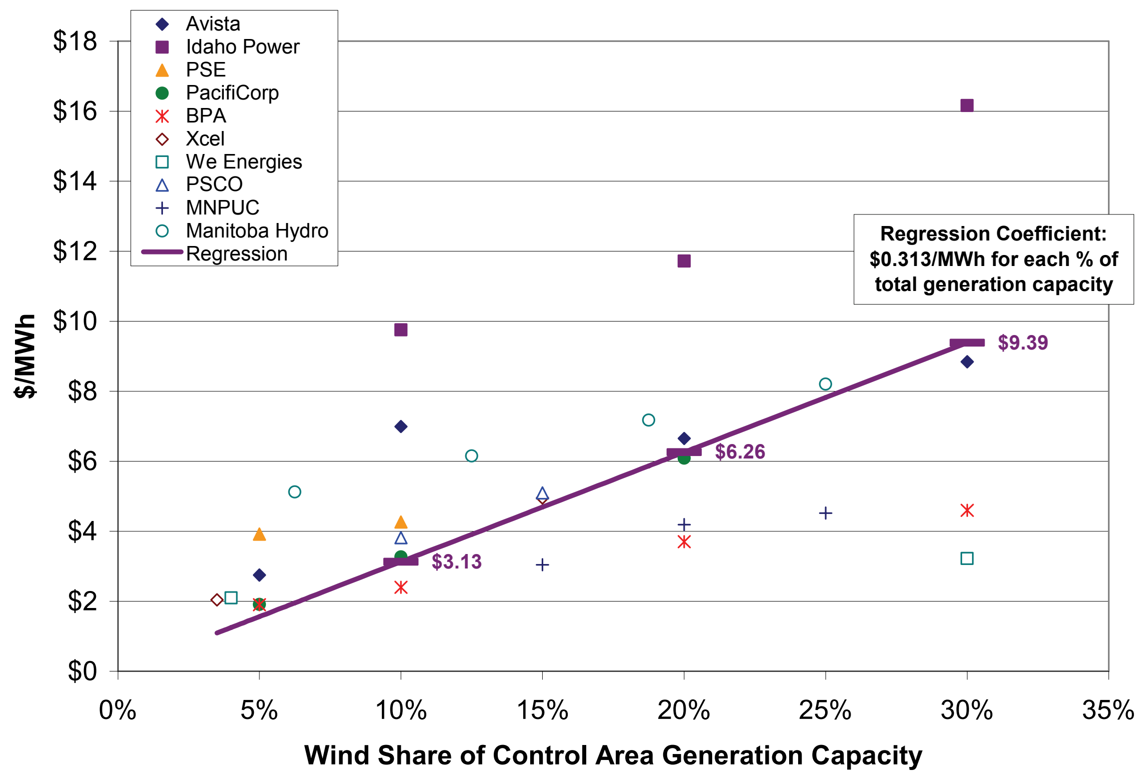


Figure 5. Cost of Integrating Wind Energy as a Function of Wind's Share of Total Generating Capacity

Thus, if there are 1000 MW of nameplate wind generating capacity in a control area that has 10,000 MW of total generating capacity, hourly integration of the wind resources will cost $3.13 for each MWh of wind energy generated. If wind's share of control area generation doubles to 20%, the hourly cost will double to $6.26/MWh, and if wind's share triples to 30%, the cost triples to $9.39/MWh.

However, the hourly cost applies to all wind energy generated, meaning that as the amount of wind generated doubles, the total integration cost quadruples. Figure 2 shows how the total cost of wind integration varies with wind's share of total system capacity. The figure assumes a control area size of 50,000 MW, and assumes that all wind energy facilities operate at a 34% capacity factor. The figure shows that for low levels of wind generation, the cost of integration is very low: only $30 million for nearly 10,000 GWh of wind generation. However, as wind generation approaches 20,000 GWh, the total cost of integration is over $120 million. At 30,000 GWh, the cost is approximately $275 million.

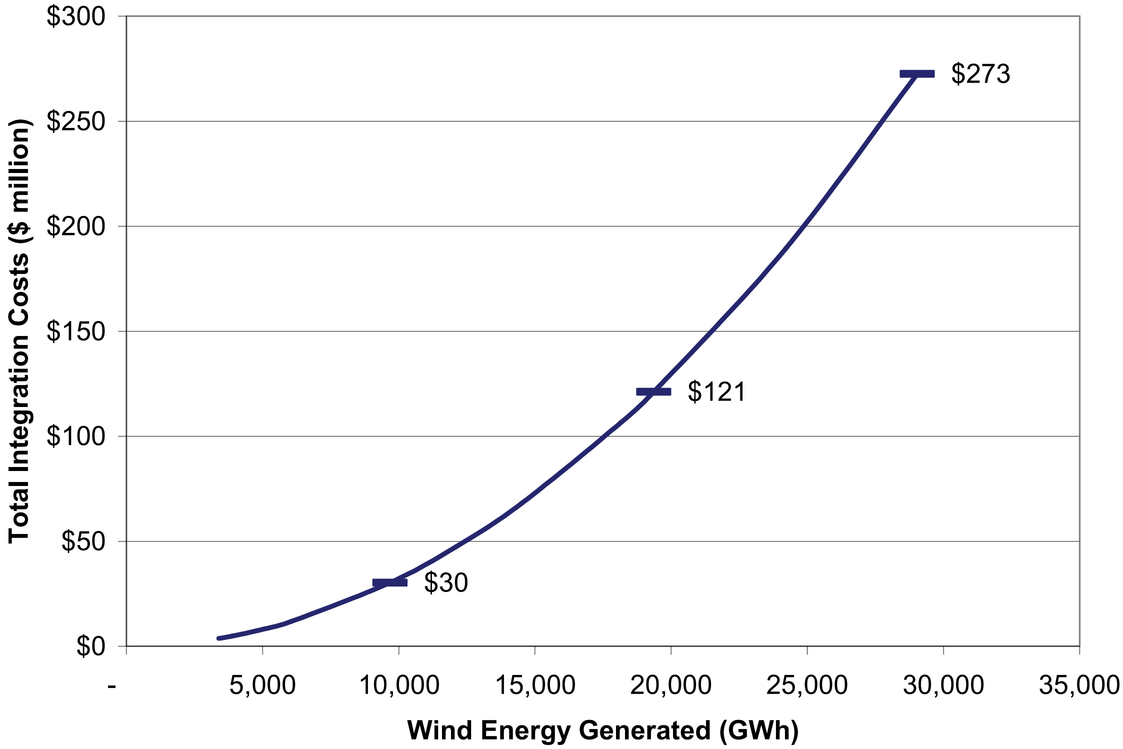


Figure 6. Cost of Integrating Wind Energy in a 50,000 MW Control Area, as a Function of Total Wind Energy Generated

Implementation

Because some regions have more than one control area, an adjustment is required due to the fact that the actual control area into which the wind generation will be integrated is smaller than the regional sum of generating capacity. To account for this, we assume that all wind will be integrated into the largest control area in the region. We apply a scaling factor to the integration costs based on the size of the largest system relative to the total peak load in the region. We take the peak demand of the largest TEPPC zone as the measure of the largest system in the region, with the following exceptions: for California, we combine all of the TEPPC areas that are served by the CAISO; for British Columbia, we combine the BC Hydro and FortisBC zones; for Utah-Southern Idaho, we use the size of the PacifiCorp East (PACE) control area even though not all of the control area is contained with the Utah-Southern Idaho region; for Wyoming, we use an allocated share of the PacifiCorp East control area. The TEPPC database includes only one region for the Northwest, even though the area has multiple control areas. However, we do not adjust the Northwest scaling factor because the cost of integrating wind in that region is likely to be substantially lower than in other WECC regions due to the region's endowment of large hydro resources. Scaling factors are listed below in Table 1.

The wind integration cost function described above is multiplied by wind's share of area generation for each WECC region, and the total costs are summed for each case. In the GHG Calculator, the user can specify a different wind energy integration cost coefficient.

Table 11. Wind Integration Cost Scaling Factors for Each WECC Region

	2017 Peak Load by Region (MW)	Largest TEPPC Load Area in Region (MW)	Integration Cost Scaling Factor
AB	13,448	13,448	1.00
AZ	32,140	24,281	1.32
BC	12,507	12,507	1.00
CA	68,683	60,473	1.14
CFE	3,608	3,608	1.00
CO	14,410	9,336	1.54
MT	1,874	1,782	1.05
NM	5,084	3,119	1.63
NV	2,293	2,293	1.00
NW	28,463	28,463	1.00
UT	9,893	8,156	1.21
WY	2,375	2,121	1.12

Study References

Northwest Wind Integration Action Plan, Northwest Power Planning and Conservation Council and others, March 2007, http://www.nwcouncil.org/energy/Wind/Default.asp (summarizes studies by Avista, Idaho Power, PacifiCorp, Puget Sound Energy, and BPA)

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29. Firming Cost

Cost of Firming Intermittent Resources

For the selection of resources in the GHG model based on cost ranking in a supply curve, it is important to ensure that the ranking methodology results in a fair comparison among resources with differently on-peak availability. Resources that are available during system peaks can provide both energy and on-peak capacity, while resources that are not available during peak hours provide only energy. Most conventional resources and some renewable resources have a high availability during system peaks. However, intermittent resources such as wind and solar energy are not always available to produce energy during system peaks. A fair comparison between intermittent and dispatchable resources must therefore include some estimate of the differential cost of procuring capacity to meet system peaks.

E3's ranking methodology includes a penalty for the cost of firming all resources. For each resource type, E3 adds a capacity cost to "firm up" the resource to 115% of an assumed on-peak capacity value, which includes 15% to account for planning reserves. The capacity cost includes capital costs, fixed O&M costs, taxes and insurance for a gas-fired, simple-cycle combustion turbine. An assumed energy benefit, equal to the dispatch savings that the CT would provide, is subtracted from the capital costs.

Table 1 below shows the base capacity factor, the assumed capacity value on peak, and the firming penalty for each resource type. It is important to note that the firming penalty is used for ranking purposes only. E3 conducts a separate load-resource balance once all of the resources are added, and adds capacity only as needed to ensure reliable service.

Table 1: Firming Penalty for Each Resource Type in E3 Ranking

	Base Capacity Factor	Capacity Value on Peak	Firming Penalty ($/kW-yr.)
Biogas	80%	85%	$ 26.07
Biomass	80%	85%	$ 26.07
Coal IGCC	85%	90%	$ 20.69
Coal IGCC with CCS	85%	90%	$ 20.69
Coal ST	85%	90%	$ 20.69
Gas CCCT	90%	95%	$ 15.32
Gas CT	5%	95%	$ 15.32
Geothermal	90%	95%	$ 15.32
Hydro - Large	50%	95%	$ 15.32
Hydro - Small	50%	65%	$ 47.57
Nuclear	85%	90%	$ 20.69
Solar Thermal	40%	85%	$ 26.07
Tar Sands	80%	85%	$ 26.07
Wind	34%	10%	$ 106.69

30. New Generation Cost Summary

Summary of Costs and Resources

This report summarizes the resource and cost assumptions in the GHG model. For more details on the derivation of these costs, see the "New Generation Resources and Costs" reports for each technology, and separate reports on financing assumptions and other cost components including transmission and integration costs. The relationship among cost components and calculation steps are shown for busbar costs of new generation in Figure 1 below.

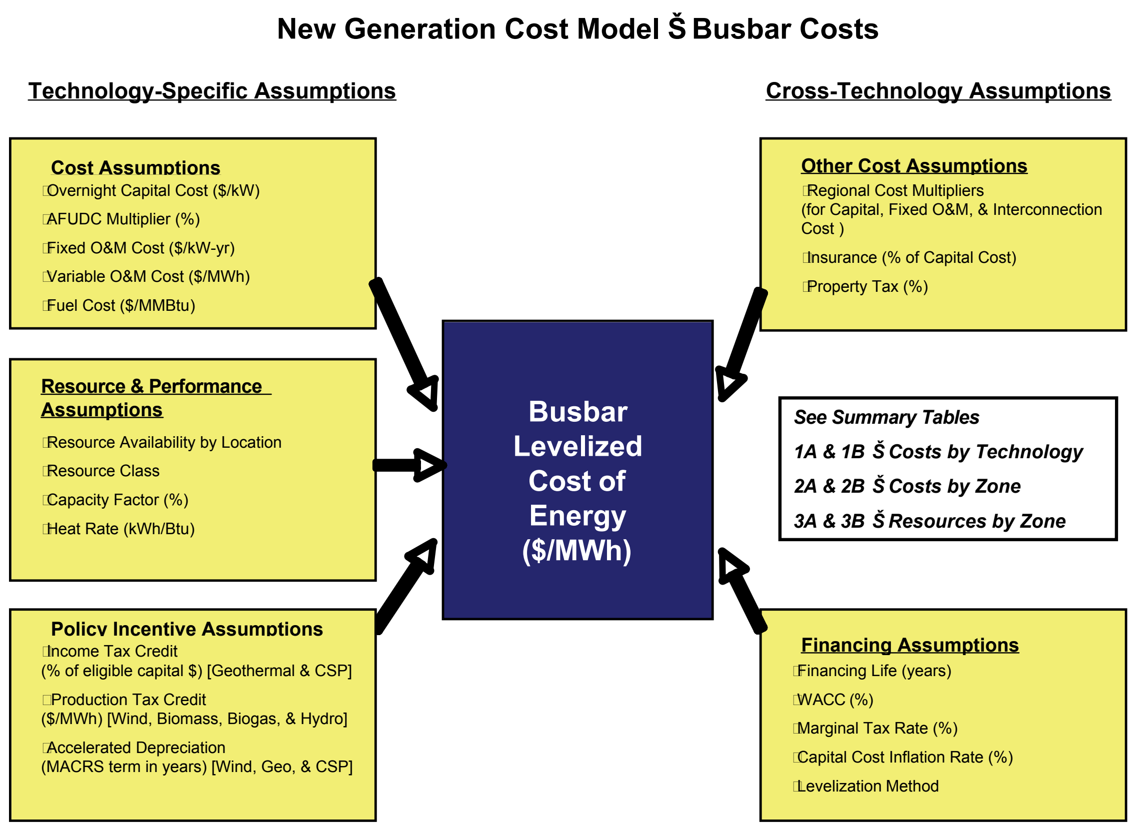
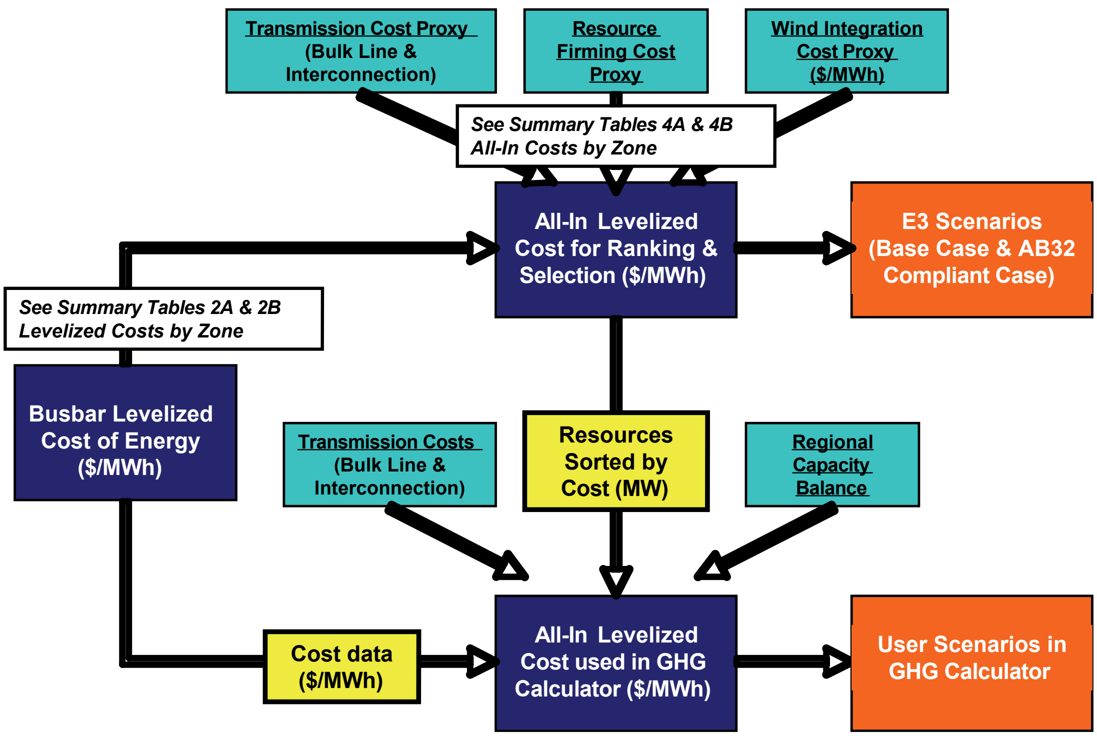


Figure 1. Busbar Costs of New Generation

The relationship among cost components and calculation steps are shown for all-in costs of new generation in Figure 2. Figure 2 also illustrates the relationship between the costs used for ranking and selection of new resources on the one hand, and for the model's calculation of system costs on the other.

New Generation Cost Model Š All-In Costs



Resources and costs for each resource type within each WECC zone in the GHG model are summarized in Tables 1A-5 that follow. Table 1 below provides a guide to these summary tables.

Table 1. Guide to Summary Tables

Table Number	Contents of Summary Table	Notes
1A	Busbar cost components by resource type for California	Sources in individual reports for each resource type
1B	Busbar cost components by resource type for Rest of WECC	Sources in individual reports for each resource type
2A	Busbar levelized cost of energy by resource by WECC zone for renewable generation	Cost methodology defined in "Financing and Incentives" report
2B	Busbar levelized cost of energy by resource by WECC zone for conventional generation	Cost methodology defined in "Financing and Incentives" report
3A	Net resources available by resource by WECC zone in MW	Net of resources already exploited in 2008 in TEPPC database
3B	Net resources available by WECC zone in GWh	Net of resources already exploited in 2008 in TEPPC database
4A	All-in levelized cost by resource type for California	Used for ranking and selection only, model costs generated separately
4B	All-in levelized cost by resource type for Rest of WECC	Used for ranking and selection only, model costs generated separately
5	Financing assumptions	See "Financing and Incentives" report for more details

Table 1A. Input Values to Busbar Energy Costs, California Resources (2008$)

Resource Technology	2020 Overnight Capital Cost ($/KW)	AFUDC Multiplier (%)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Fuel Cost ($/MMBtu)	Capacity Factor	Nominal Heat Rate (Btu/kWh)
Biogas	$3,065	115.0%	$139	$1.20	$1.43	80%	13,648
Biomass	$4,484	105.9%	$65	$1.20	$2.87	80%	8,911
Geothermal	$3,339 - $8,131	122.4%	$157 - $226	$1.20	n/a	90%	n/a
Hydro - Small	$2,539 - $5,170	122.4%	$14 - $31	$0.94 - $1.81	n/a	25% - 65%	n/a
Solar Thermal	$4,067	108.6%	$64	$1.20	n/a	37% - 40%	n/a
Wind	$1,962	105.9%	$37	$1.20	n/a	27% - 40%	n/a
Coal ST	$2,479	133.3%	$33	$1.20	$1.97	85%	8,844
Coal IGCC	$2,866	133.3%	$47	$1.20	$1.97	85%	8,309
Coal IGCC with CCS	$4,101	150.0%	$55	$1.20	$1.97	85%	9,713
Gas CCCT	$1,054	100.0%	$14	$1.20	$6.53	90%	6,917
Gas CT*	$807	114.9%	$15	$1.20	$6.53	5%	10,807
Hydro - Large	$1,486 - $2,193	122.4%	$9 - $13	$0.63 - $0.89	n/a	12% - 57%	n/a
Nuclear	$3,999	150.0%	$83	$1.20	$0.78	85%	10,400

Table 1B. Input Values to Busbar Energy Costs, Rest of WECC Resources (2008$)

Resource Technology	2020 Overnight Capital Cost ($/KW)	AFUDC Multiplier (%)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Fuel Cost ($/MMBtu)	Capacity Factor	Nominal Heat Rate (Btu/kWh)
Biogas	$2,350 - $2,835	115.0%	$107 - $128	$0.92 - $1.11	$1.43 - $1.43	80%	13,648
Biomass	$3,438 - $4,148	105.9%	$50 - $60	$0.92 - $1.11	$2.87	80%	8,911
Geothermal	$1,582 - $19,451	122.4%	$157 - $226	$0.96 - $1.11	n/a	90%	n/a
Hydro - Small	$1,758 - $4,782	122.4%	$11 - $28	$0.71 - $1.69	n/a	22% - 65%	n/a
Solar Thermal	$3,254 - $3,694	108.6%	$51 - $58	$0.96 - $1.09	n/a	36% - 39%	n/a
Wind	$1,504 - $1,815	105.9%	$28 - $34	$0.92 - $1.11	n/a	27% - 40%	n/a
Coal ST	$1,901 - $2,293	133.3%	$26 - $31	$0.92 - $1.11	$0.80 - $1.97	85%	8,844
Coal IGCC	$2,197 - $2,651	133.3%	$36 - $43	$0.92 - $1.11	$0.80 - $1.97	85%	8,309
Coal IGCC with CCS	$3,144 - $3,794	150.0%	$42 - $51	$0.92 - $1.11	$0.80 - $1.97	85%	9,713
Gas CCCT	$808 - $975	100.0%	$11 - $13	$0.92 - $1.11	$5.51 - $6.56	90%	6,917
Gas CT*	$619 - $747	114.9%	$11 - $14	$0.92 - $1.11	$5.51 - $6.56	5%	10,807
Hydro - Large	$1,122 - $2,031	122.4%	$5 - $11	$0.41 - $0.78	n/a	15% - 65%	n/a
Nuclear	$3,066 - $3,699	150.0%	$63 - $76	$0.92 - $1.11	$0.78	85%	10,400

Table 2A. Busbar Levelized Cost of Energy by Technology by Zone (2008 $/MWh)

Resource Zone	Regional Multiplier	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
AB	1.00	n/a	n/a	n/a	$110	n/a	$57 - $84
AZ-S. NV	1.00	$79	$103	n/a	n/a	$111 - $114	$57 - $73
BC	1.00	$79	$103	$59 - $74	$77 - $98	n/a	$57 - $67
CA	1.20	$91	$118	$81 - $144	$81 - $220	$128 - $137	$68 - $101
CFE	1.00	n/a	n/a	n/a	n/a	n/a	$57 - $84
CO	0.97	$77	$101	$108	n/a	$116	$55 - $65
MT	1.02	$80	$105	n/a	$61 - $126	n/a	$58 - $68
NM	0.96	$77	$100	$106 - $111	n/a	$106	$54 - $70
N. NV	1.09	$84	$110	$55 - $277	$125 - $138	$119 - $125	$62 - $92
NW	1.11	$86	$112	$98 - $111	$68 - $216	n/a	$63 - $93
UT-S. ID	1.00	$79	$103	$71 - $110	$64 - $195	$118	$57 - $73
WY	0.92	$74	$97	n/a	$66 - $99	n/a	$52 - $61

Table 2B. Busbar Levelized Cost of Energy by Technology by Zone (2008 $/MWh)

Resource Zone	Regional Multiplier	Coal ST	Coal IGCC	Coal IGCC with CCS	Gas CCCT	Gas CT*	Hydro - Large	Nuclear
AB	1.00	$72	$78	$115	$57	$315	$71	$101
AZ-S. NV	1.00	$69	$75	$112	$63	$325	n/a	$101
BC	1.00	$72	$78	$115	$58	$317	$61 - $127	$101
CA	1.20	$82	$90	$133	$67	$377	$72 - $283	$119
CFE	1.00	$72	$78	$115	$63	$326	n/a	n/a
CO	0.97	$65	$71	$106	$56	$308	n/a	$98
MT	1.02	$63	$70	$106	$57	$320	n/a	$103
NM	0.96	$69	$75	$111	$60	$312	n/a	$97
N. NV	1.09	$77	$83	$123	$65	$349	n/a	$109
NW	1.11	$78	$85	$125	$59	$344	$93 - $177	$111
UT-S. ID	1.00	$67	$74	$110	$57	$316	$53 - $131	$101
WY	0.92	$58	$64	$97	$55	$295	n/a	$94

Table 3A. Net Resources Available by Zone (MW)

Resource Zone	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind	Hydro - Large	All Other Conventional Resources
AB	0	0	0	100	0	11,986	100	No Limit
AZ-S. NV	33	43	0	0	141,243	1,826	0	No Limit
BC	50	208	185	1,521	0	4,601	3,342	No Limit
CA	300	600	3,008	221	89,650	53,044	440	No Limit
CFE	0	0	0	0	0	5,020	0	No Limit
CO	59	44	20	0	18,050	4,883	0	No Limit
MT	5	162	0	37	0	54,437	0	No Limit
NM	18	26	80	0	66,897	10,805	0	No Limit
N. NV	15	15	1,469	10	150,062	5,523	0	No Limit
NW	88	1,060	335	230	0	15,489	1,861	No Limit
UT-S. ID	21	181	1,067	221	43,153	2,601	143	No Limit
WY	2	22	0	17	0	138,637	0	No Limit

Table 3B. Net Resources Available by Zone (GWh)

Resource Zone	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind	Hydro - Large	All Other Conventional Resources
AB	0	0	0	438	0	30,193	438	No Limit
AZ-S. NV	234	302	0	0	473,037	5,235	0	No Limit
BC	350	1,458	1,459	6,660	0	15,420	14,379	No Limit
CA	2,102	4,205	23,717	844	308,282	135,895	806	No Limit
CFE	0	0	0	0	0	12,519	0	No Limit
CO	416	306	158	0	56,182	15,339	0	No Limit
MT	35	1,135	0	178	0	166,721	0	No Limit
NM	127	179	631	0	226,215	32,670	0	No Limit
N. NV	107	104	11,583	42	494,958	15,780	0	No Limit
NW	617	7,430	2,641	937	0	43,629	3,154	No Limit
UT-S. ID	149	1,271	8,410	907	137,013	7,695	601	No Limit
WY	15	155	0	94	0	433,276	0	No Limit

Table 4A. Levelized Cost for Ranking & Selection, California* Resources (2008 $/MWh)

Resource Technology	Levelized Busbar Cost	Interconnection Cost	Transmission Cost - Bulk	Fimring Resource Cost	Wind Integration Cost	Total Levelized Cost for Ranking & Selection
Biogas	$91	n/a	$1.01	$1.04	$0.00	$93
Biomass	$118	n/a	$1.01	$1.04	$0.00	$120
Geothermal	$81 - $144	n/a	$1.03 - $19.18	$0.92 - $0.92	$0.00	$63 - $286
Hydro - Small	$81 - $220	n/a	$2.71 - $51.36	$6.10 - $15.91	$0.00	$92 - $283
Solar Thermal	$128 - $137	n/a	$4.44 - $46.07	$5.43 - $5.80	$0.00	$138 - $188
Wind	$68 - $101	n/a	$2.51 - $63.92	$22.22 - $32.91	$5.35	$95 - $203
Coal ST	$82	$0.77	n/a	$0.97	$0.00	$84
Coal IGCC	$90	$0.77	n/a	$0.97	$0.00	$92
Coal IGCC with CCS	$133	$0.77	n/a	$0.97	$0.00	$135
Gas CCCT	$67	$0.29	n/a	$0.92	$0.00	$68
Gas CT*	$377	$5.26	n/a	$16.57	$0.00	$398
Hydro - Large	$72 - $283	$0.16 - $0.74	n/a	$3.02 - $14.12	$0.00	$75 - $298
Nuclear	$119	$0.77	n/a	$0.97	$0.00	$121

Table 4B. Levelized Cost for Ranking & Selection, Rest of WECC Resources (2008 $/MWh)

Resource Technology	Levelized Busbar Cost	Interconnection Cost	Transmission Cost - Bulk	Fimring Resource Cost	Wind Integration Cost	Total Levelized Cost for Ranking & Selection
Biogas	$74 - $86	$0.63 - $0.76	n/a	$0.79 - $0.96	$0.00	$76 - $87
Biomass	$97 - $112	$0.63 - $0.76	n/a	$0.79 - $0.96	$0.00	$99 - $113
Geothermal	$55 - $277	$0.01 - $1.67	n/a	$0.74 - $0.85	$0.00	$56 - $279
Hydro - Small	$61 - $216	$0.07 - $5.48	n/a	$4.67 - $15.93	$0.00	$66 - $230
Solar Thermal	$106 - $125	$0.19 - $8.49	n/a	$4.50 - $5.32	$0.00	$111 - $135
Wind	$52 - $93	$0.27 - $64.42	n/a	$17.03 - $30.45	$1.65 - $10.84	$72 - $156
Coal ST	$58 - $78	$0.59 - $0.72	n/a	$0.75 - $0.90	$0.00	$59 - $79
Coal IGCC	$64 - $85	$0.59 - $0.72	n/a	$0.75 - $0.90	$0.00	$65 - $86
Coal IGCC with CCS	$97 - $125	$0.59 - $0.72	n/a	$0.75 - $0.90	$0.00	$98 - $127
Gas CCCT	$55 - $65	$0.22 - $0.27	n/a	$0.71 - $0.85	$0.00	$56 - $66
Gas CT*	$295 - $349	$4.03 - $4.86	n/a	$12.70 - $15.32	$0.00	$312 - $369
Hydro - Large	$53 - $177	$0.22 - $10.95	n/a	$2.21 - $10.81	$0.00	$55 - $186
Nuclear	$94 - $111	$0.59 - $0.72	n/a	$0.75 - $0.90	$0.00	$95 - $113

Table5. Input Values to Busbar Energy Costs, All Technologies (2008$)

Parmeter	Value
Ownership	IPP
Financing Life	20 years
Marginal Tax Rate (Fed & State)	40.75%
Insurance (% of Overnight Capital Cost)	0.5%
Property Tax (% of Overnight Capital Cost	1.0%

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31. Resource Ranking and Selection

Introduction

This paper describes E3's methodology for ranking and selecting new resources for use in developing the Reference and Target cases. E3 ranked generating resources first for the purpose of calculating the resource mix in other WECC zones, and second for calculating the mix and cost of renewable resources located in renewable resource zones that could be available to serve California. The GHG Calculator tallies the total cost of energy service under the selected resources as the sum of the capital, financing, and variable costs, plus the cost of integrating intermittent resources. The variable costs calculated in the GHG calculator are based on the hourly dispatch of resources from the PLEXOS simulation, after the system generation and transmission resources are fully defined. However, in order to select the resources to add to the system, a method for ranking resources of different types must be developed and applied.

The general steps in ranking and selection of new resources are:

1. Determine quantities of available resources within each WECC region and California resource zone by resource type.

2. Develop levelized total resource costs for new resources within each WECC region and California zone by resource type, using busbar resource costs, transmission interconnection costs, and proxies for firming and integration costs.

3. Rank resources by levelized cost within the region based on the total resource cost.

4. Select lowest cost resources for each WECC region until that region's RPS, energy and capacity requirements are met.

5. Re-rank the remaining resources for potential delivery to California using estimates of the cost of transmission from each WECC region and California resource zone to load centers in California.

6. Select lowest-cost resources for meeting California's load and policy requirements.

Cost and Availability of Renewable Resources by Region

The GHG model assesses the cost and availability of renewable resources within each of 24 resource areas or zones. The methodology for developing the busbar costs and resource availability are described in the *New Generation Resources and Costs* papers. The table below summarizes the availability of renewable resources in each of the 24 resource regions.

Table CA-1. Net Resources Available by Resource Cluster (MW)

Resource Cluster	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	300	600	0	0	0	0
Bay Delta	0	0	0	27	0	3,055
CFE	0	0	0	0	0	5,020
Geysers/Lake	0	0	538	11	0	170
Imperial	0	0	1,986	0	12,529	3,414
Mono/Inyo	0	0	151	18	17,094	2,661
NE NV	0	0	0	0	0	1,488
Northeast CA	0	0	255	8	0	2,931
Reno Area/Dixie Valley	0	0	1,316	0	7,449	3,230
Riverside	0	0	0	0	7,234	3,394
San Bernardino	0	0	48	0	21,683	14,007
San Diego	0	0	0	3	5,544	2,198
Santa Barbara	0	0	0	0	0	575
Tehachapi	0	0	0	0	16,853	10,755

Table 3A. Net Resources Available by Zone (MW)

Resource Zone	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind	Hydro - Large	All Other Conventional Resources
AB	0	0	0	100	0	11,986	100	No Limit
AZ-S. NV	33	43	0	0	141,243	1,826	0	No Limit
BC	50	208	185	1,521	0	4,601	3,342	No Limit
CA	300	600	3,008	221	89,650	53,044	440	No Limit
CFE	0	0	0	0	0	5,020	0	No Limit
CO	59	44	20	0	18,050	4,883	0	No Limit
MT	5	162	0	37	0	54,437	0	No Limit
NM	18	26	80	0	66,897	10,805	0	No Limit
N. NV	15	15	1,469	10	150,062	5,523	0	No Limit
NW	88	1,060	335	230	0	15,489	1,861	No Limit
UT-S. ID	21	181	1,067	221	43,153	2,601	143	No Limit
WY	2	22	0	17	0	138,637	0	No Limit

Costs Used for Resource Ranking and Selection

The resource ranking and selection methodology determines the mix of resources in each resource region. In addition to the resource-specific busbar costs, the ranking method also considers the costs for generation interconnection, firming, integration of wind resources, and transmission from the resource area to California load centers to arrive at an estimate of total delivered resource cost. The costs for firming, integration and transmission are deemed values based on the expected impact of each resource on the total system costs and are used here for ranking purposes only. The actual costs in these categories are tallied only after all resources are selected and added separately after the model determines to what extent new capacity and transmission are needed.

The first purpose of the resource ranking methodology is to determine which resources are added to serve loads outside of California. The model assumes that each region adds local renewable resources – resources located in that region – to meet its own RPS target. After local needs are satisfied, remaining resources are made available for delivery to California loads.

Table CA-3 below shows the busbar levelized cost of energy by resource type within the each resource region. These costs are based on the resource class specific data within each region and other costs detailed in the technology-specific cost reports and summarized in the "New Generation Cost Summary" report.

Table CA-3. Busbar Levelized Cost of Energy by Technology by Resource Cluster (2008 $/MWh)

Resource Cluster	Regional Multiplier	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	1.20	$91	$118	n/a	n/a	n/a	n/a
Bay Delta	1.20	n/a	n/a	n/a	$81 - $119	n/a	$74 - $101
CFE	1.00	n/a	n/a	n/a	n/a	n/a	$57 - $84
Geysers/Lake	1.20	n/a	n/a	$87 - $115	$176 - $177	n/a	$74 - $101
Imperial	1.20	n/a	n/a	$85 - $144	n/a	$128	$68 - $101
Mono/Inyo	1.20	n/a	n/a	$81 - $107	$88 - $220	$130 - $137	$68 - $101
Northeast NV	1.09	n/a	n/a	n/a	n/a	n/a	$62 - $80
Northeast CA	1.20	n/a	n/a	$81 - $103	$120 - $186	n/a	$68 - $101
Reno Area/Dixie Valley	1.09	n/a	n/a	$55 - $277	n/a	$119 - $125	$62 - $92
Riverside	1.20	n/a	n/a	n/a	n/a	$128	$68 - $101
San Bernardino	1.20	n/a	n/a	$92	n/a	$128	$68 - $101
San Diego	1.20	n/a	n/a	n/a	$107	$130 - $136	$68 - $101
Santa Barbara	1.20	n/a	n/a	n/a	n/a	n/a	$68 - $101
Tehachapi	1.20	n/a	n/a	n/a	n/a	$130	$68 - $101
NV	1.20	$84	$110	$77	$125 - $138	$119 - $125	$62 - $80
Alberta	1.20	n/a	n/a	n/a	$110	n/a	$57 - $84
Arizona-So. Nevada	1.20	$79	$103	n/a	n/a	$111 - $114	$57 - $73
British Columbia	1.20	$79	$103	$59 - $74	$77 - $98	n/a	$57 - $67
Colorado	1.20	$77	$101	$108	n/a	$116	$55 - $65
Montana	1.20	$80	$105	n/a	$61 - $126	n/a	$58 - $68
New Mexico	1.20	$77	$100	$106 - $111	n/a	$106	$54 - $70
Northern Nevada	1.20	$84	$110	$55 - $277	$125 - $138	$119 - $125	$62 - $92
Northwest	1.20	$86	$112	$98 - $111	$68 - $216	n/a	$63 - $93
Utah-Southern Idaho	1.20	$79	$103	$71 - $110	$64 - $195	$118	$57 - $73
Wyoming	1.20	$74	$97	n/a	$66 - $99	n/a	$52 - $61

The delivered cost of energy to California loads depends in part on the cost of building the necessary transmission infrastructure. Transmission cost is a function of the size of the transmission line and the amount of energy it can carry. Larger transmission lines are generally less expensive to construct on a $/MWh basis than smaller lines. However, depending on the resources available in the source region, constructing a larger transmission line may result in the addition of relatively more expensive resources, as the low-cost resources are exhausted. Thus, the total delivered cost involves a tradeoff between resource costs and transmission costs.

The GHG Calculator comes with a pre-selected quantity for each resource type within each resource region, depending on the size of the transmission line that is constructed to that region. For each region and transmission line size, a heterogeneous bundle of renewable resources is selected depending on the cost and availability of resources in that region. Different bundles are selected for different transmission line sizes. Transmission lines can be sized anywhere from 250 MW to 6000 MW of capacity.

Table 4 shows an example supply curve for the Imperial region of southeastern California. Interconnection, firming, integration and transmission costs are added to the busbar costs for each resource in order to estimate its total resource cost used for ranking. The resources are then sorted by total resource cost, and the least-cost resources are selected until the user-specified transmission line is filled. For example, a 1500 MW transmission line is filled with the first three resources in the supply curve, at an average cost of approximately $93/MWh.

Several higher-cost resources are added to fill a 2000 MW transmission line, raising the average zonal cost to nearly $100/MWh.[77]

Table 4. Renewable Resource Supply Curve for Imperial Region

Name	Type	Available Capacity (MW)	Available Energy (GW)	Busbar Cost ($/MWh)	Inter-connection ($/MWh)	*Firming ($/MWh)	*Integration ($/MWh)	*Trans-mission ($/MWh)	Total Resource Cost ($/MWh)	Cumulative MW Selected	Zonal Avg. Cost ($/MWh)
Salton Sea	Geothermal	1,404	11,069	$84.79	$0.29	$0.92	$0.00	$6.76	$92.47	1,404	$ 92.47
Mount Signal	Geothermal	19	150	$94.93	$0.12	$0.92	$0.00	$6.76	$102.60	1,423	$ 92.60
North Brawley	Geothermal	135	1,064	$95.52	$0.03	$0.92	$0.00	$6.76	$103.20	1,558	$ 93.52
Heber	Geothermal	42	331	$98.54	$0.03	$0.92	$0.00	$6.76	$106.22	1,600	$ 93.85
CA Wind- Imperial, Zone 33 - Class 7	Wind	48	169	$68.10	$1.64	$22.22	$5.35	$15.20	$110.87	1,648	$ 94.08
Superstition Mountain	Geothermal	10	75	$104.33	$0.44	$0.92	$0.00	$6.76	$112.00	1,658	$ 94.18
Niland	Geothermal	76	599	$105.09	$0.04	$0.92	$0.00	$6.76	$112.77	1,734	$ 95.01
CA Wind- Imperial, Zone 33 - Class 6	Wind	83	268	$73.63	$1.78	$24.02	$5.35	$16.43	$119.43	1,816	$ 95.49
CA Wind- Imperial, Zone 33 - Class 5	Wind	141	420	$80.12	$1.93	$26.14	$5.35	$17.88	$129.50	1,957	$ 96.50
Dunes	Geothermal	11	87	$121.96	$0.16	$0.92	$0.00	$6.76	$129.63	1,968	$ 96.70
East Brawley	Geothermal	129	1,017	$126.94	$0.04	$0.92	$0.00	$6.76	$134.61	2,097	$ 99.23
East Mesa	Geothermal	92	725	$133.76	$0.05	$0.92	$0.00	$6.76	$141.43	2,189	$ 101.14
CA Wind- Imperial, Zone 33 - Class 4	Wind	643	1,745	$87.88	$2.12	$28.67	$5.35	$19.61	$141.51	2,832	$ 105.12
South Brawley	Geothermal	62	489	$135.24	$0.19	$0.92	$0.00	$6.76	$142.92	2,894	$ 106.13
CA - Solar Thermal, Zone 33 - Imperial	Solar Thermal	12,529	43,902	$127.86	$0.85	$5.43	$0.00	$15.20	$148.49	15,423	$ 136.07
Glamis	Geothermal	6	50	$143.90	$0.28	$0.92	$0.00	$6.76	$151.57	15,429	$ 136.08
CA Wind- Imperial, Zone 33 - Class 3	Wind	2,500	5,913	$100.90	$2.43	$32.91	$5.35	$22.52	$161.68	17,929	$ 138.31

** Cost category that is included for ranking, but for which total costs are calculated separately in the GHG Calculator.*

Table 5 shows how the Imperial Valley resources detailed above compare with the other resources available to California, for transmission line size increments of 1000 MW and 2000 MW. The results for these two sizes are excerpted from the supply curve in the GHG model, which includes transmission size increments from 250 MW through 6000 MW. The table indicates that, for a transmission line of 1000 MW, the $94.37/MWh total resource cost for the Imperial Valley resources is the lowest among all resource regions. Similarly, for a transmission line of 2000 MW, the Imperial Valley's total resource cost of $97.99 is the lowest. Other promising resource areas are Northeast California, the Reno/Dixie Valley area, the Geysers/Lake County area, and Tehachapi.

[77] Transmission costs are treated as linear in this demonstration; in the model, a different transmission cost is specified for each MW size.

Table 5. Selection from Resource Supply Curve

Resource Cluster	Size of Line (MW)	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind	Zonal Avg. Cost ($/MWh)
Northeast CA	1,000	-	-	255	-	-	743	$ 109.26
Geysers/Lake	1,000	-	-	538	-	-	170	$ 117.49
Bay Delta	1,000	-	-	-	-	-	973	$ 134.95
Tehachapi	1,000	-	-	-	-	-	971	$ 122.61
San Bernardino	1,000	-	-	47	-	-	924	$ 120.76
Mono/Inyo	1,000	-	-	147	-	11	799	$ 137.84
San Diego	1,000	-	-	-	-	154	843	$ 129.14
Imperial	1,000	-	-	1,000	-	-	-	$ 94.37
Riverside	1,000	-	-	-	-	-	1,000	$ 125.99
Santa Barbara	1,000	-	-	-	-	-	576	$ 147.54
CA - Distributed	1,000	300	600	-	-	-	-	$ 112.29
CFE	1,000	-	-	-	-	-	1,000	$ 120.76
Reno Area/Dixie Valley	1,000	-	-	839	-	-	132	$ 107.45
NE NV	1,000	-	-	-	-	-	971	$ 165.61
Alberta	1,000	-	-	-	-	-	808	$ 296.35
Arizona-Southern Nevada	1,000	-	-	-	-	956	36	$ 134.94
British Columbia	1,000	-	192	-	-	-	264	$ 166.91
Colorado	1,000	-	-	19	-	-	906	$ 212.59
Montana	1,000	5	152	-	-	-	782	$ 153.47
New Mexico	1,000	-	25	77	-	-	855	$ 149.84
South Central Nevada	1,000	15	15	78	-	128	760	$ 127.54
Northwest	1,000	-	773	187	-	-	-	$ 137.39
Utah-Southern Idaho	1,000	-	175	757	-	-	-	$ 124.20
Wyoming	1,000	2	21	-	-	-	909	$ 151.99
Northeast CA	2,000	-	-	255	-	-	1,742	$ 123.07
Geysers/Lake	2,000	-	-	538	-	-	170	$ 118.55
Bay Delta	2,000	-	-	-	-	-	1,973	$ 141.69
Tehachapi	2,000	-	-	-	-	-	1,942	$ 121.83
San Bernardino	2,000	-	-	47	-	-	1,895	$ 127.43
Mono/Inyo	2,000	-	-	147	-	982	799	$ 146.36
San Diego	2,000	-	-	-	-	1,154	843	$ 136.05
Imperial	2,000	-	-	1,728	-	-	272	$ 97.99
Riverside	2,000	-	-	-	-	975	1,025	$ 132.38
Santa Barbara	2,000	-	-	-	-	-	576	$ 158.46
CA - Distributed	2,000	300	600	-	-	-	-	$ 113.12
CFE	2,000	-	-	-	-	-	2,000	$ 125.51
Reno Area/Dixie Valley	2,000	-	-	1,032	-	-	910	$ 111.71
NE NV	2,000	-	-	-	-	-	1,444	$ 180.59
Alberta	2,000	-	-	-	-	-	1,706	$ 234.66
Arizona-Southern Nevada	2,000	-	-	-	-	1,947	36	$ 140.63
British Columbia	2,000	-	192	-	-	-	1,422	$ 159.12
Colorado	2,000	-	-	19	-	108	1,721	$ 181.53
Montana	2,000	5	152	-	-	-	1,720	$ 136.72
New Mexico	2,000	-	25	77	-	-	1,811	$ 143.89
South Central Nevada	2,000	15	15	78	-	1,124	760	$ 141.32
Northwest	2,000	-	1,018	187	-	-	690	$ 137.76
Utah-Southern Idaho	2,000	-	175	1,005	-	-	710	$ 124.03
Wyoming	2,000	2	-	-	-	-	1,869	$ 131.09

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32. California Resource Zones

California Zonal Model for Renewable Resources

Within California, the GHG model provides a greater level of locational granularity for the ranking and selection of renewable resources within the state than it does for the 11 WECC zones outside California. This development involves the following steps:

- Allocating renewable resources at the county level

- Identify zones within the state with large concentration of renewable generation potential

- Group together wind, solar thermal, geothermal, and small hydro, resource potential located near each of these each high-concentration areas, aggregating up from the county level. Group biomass and biogas resources as a set of distributed resources located throughout the state.

- Sort the resources potential within each zone in ascending order of levelized cost (after adding a proxy amount for firming and integration to the busbar cost of intermittent resources).

The results of these steps are described in this report.[78]

Allocating Renewable Resources to California Counties

The public data available for determining the renewable resources available in different geographic areas of California is described in the table below:

Summary of Resource Data for California

Resource	Wind	Wind	CSP	CSP	Geo	Small Hydro	Biomass/ Biogas
Data Source	NREL	NREL	CEC RRDR	CEC RRDR	EIA/ WGA/ GeothermEx	EIA/INL	CBC/CEC
Geographic Level	NREL Region ***(groups of 1 to 10 counties)***	County	NREL Region	County	Site specific –> mapped to County	County	State-Wind for Filtered Resource
Number of CA Zones	14	58	14	58	58	58	1
Resource Classes	**5:** Class 3 through Class 7	**2:** High WS & Low WS	**5:** Class 1 to Class 5	**1:** No distinction	**Infinite:** Site specific cost & cf	**Infinite:** Site specific cost & cf	**1:** No distinction
Total CA resource potential (MW)	53,044	99,948	89,117	66,160	3,008	221	600 biomass 300 biogas

[78] Note: Some cost numbers may change in later versions of the GHG model.

In comparing published data principally available from either NREL or CEC studies, E3 determined that NREL data has better resource class (or quality) resolution, with five wind and CSP classes, but lower geographic resolution, as NREL regions are groupings of between one and ten counties, with only 14 zones for the whole state. Much of the CEC resource data, on the other hand, is specific at the level of either resource potential or actual proposed sites within each of California's 58 counties.

To obtain the best features of both resource quality and geographic resolution, E3 developed the approach of allocating wind and CSP resource potential in the 14 NREL zones to the 58 California counties based on that county's proportional share of resources according to CEC data. For example, E3 used the county resource shares of CEC's High Wind Speed class (600-800 W/m^2) potential for allocating Class 6 and Class 7 NREL wind potential, and used the county share of CEC's Low Wind Speed class (400-600 W/m^2) potential for allocating Class 3, 4, and 5 NREL wind data. Similar methods were used for CSP, while geothermal and hydro data was already site-specific and mappable at the county level. Biomass and biogas are modeled as a distributed resource and not assigned to counties.

The results of this analysis are described in the following tables.

Table County-1. Net Resources Available by County (MW)

CA County	Total Resources	Biogas	Biomass	Geo-thermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	900	300	600	0	0	0	0
Alameda	32	n/a	n/a	0	15	0	17
Alpine	187	n/a	n/a	0	0	0	187
Amador	18	n/a	n/a	0	15	0	3
Butte	46	n/a	n/a	0	0	0	46
Calaveras	11	n/a	n/a	0	10	0	1
Colusa	34	n/a	n/a	0	0	0	34
Contra Costa	12	n/a	n/a	0	12	0	0
Del Norte	99	n/a	n/a	0	0	0	99
El Dorado	20	n/a	n/a	0	0	0	20
Fresno	108	n/a	n/a	0	29	0	79
Glenn	4	n/a	n/a	0	0	0	4
Humboldt	954	n/a	n/a	152	0	0	802
Imperial	17,929	n/a	n/a	1,986	0	12,529	3,414
Inyo	17,640	n/a	n/a	80	9	15,281	2,271
Kern	27,608	n/a	n/a	0	0	16,853	10,755
Kings	4	n/a	n/a	0	0	0	4
Lake	638	n/a	n/a	538	11	0	88
Lassen	1,002	n/a	n/a	7	0	0	995
Los Angeles	14,079	n/a	n/a	0	0	8,713	5,366
Madera	7	n/a	n/a	0	0	0	7
Marin	19	n/a	n/a	0	0	0	19
Mariposa	0	n/a	n/a	0	0	0	0
Mendocino	257	n/a	n/a	0	0	0	257
Merced	221	n/a	n/a	0	25	0	196
Modoc	434	n/a	n/a	37	0	0	397
Mono	2,284	n/a	n/a	71	9	1,813	390
Monterey	90	n/a	n/a	0	5	0	85
Napa	58	n/a	n/a	25	0	0	33
Nevada	27	n/a	n/a	0	0	0	27
Orange	180	n/a	n/a	0	0	0	180
Placer	30	n/a	n/a	0	0	0	30
Plumas	235	n/a	n/a	0	30	0	205
Riverside	10,627	n/a	n/a	0	0	7,234	3,394
Sacramento	2	n/a	n/a	0	0	0	2
San Benito	12	n/a	n/a	0	0	0	12
San Bernardino	35,738	n/a	n/a	48	0	21,683	14,007
San Diego	7,745	n/a	n/a	0	3	5,544	2,198
San Francisco	1	n/a	n/a	0	0	0	1
San Joaquin	338	n/a	n/a	0	0	0	338
San Luis Obispo	87	n/a	n/a	0	0	0	87
San Mateo	11	n/a	n/a	0	0	0	11
Santa Barbara	575	n/a	n/a	0	0	0	575
Santa Clara	7	n/a	n/a	0	2	0	5
Santa Cruz	2	n/a	n/a	0	2	0	1
Shasta	732	n/a	n/a	0	3	0	729
Sierra	103	n/a	n/a	0	25	0	78
Siskiyou	1,026	n/a	n/a	211	4	0	811
Solano	3,019	n/a	n/a	0	0	0	3,019
Sonoma	48	n/a	n/a	0	0	0	48

Table County-2. Net Resources Available by County (GWh)

CA County	Total Resources	Biogas	Biomass	Geo-thermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	6,307	2,102	4,205	0	0	0	0
Alameda	126	n/a	n/a	0	86	0	40
Alpine	485	n/a	n/a	0	0	0	485
Amador	78	n/a	n/a	0	69	0	9
Butte	113	n/a	n/a	0	0	0	113
Calaveras	38	n/a	n/a	0	35	0	3
Colusa	82	n/a	n/a	0	0	0	82
Contra Costa	58	n/a	n/a	0	58	0	0
Del Norte	251	n/a	n/a	0	0	0	251
El Dorado	52	n/a	n/a	0	0	0	52
Fresno	258	n/a	n/a	0	65	0	193
Glenn	9	n/a	n/a	0	0	0	9
Humboldt	3,349	n/a	n/a	1,201	0	0	2,148
Imperial	68,073	n/a	n/a	15,657	0	43,902	8,514
Inyo	57,522	n/a	n/a	631	49	51,157	5,685
Kern	87,937	n/a	n/a	0	0	58,285	29,652
Kings	9	n/a	n/a	0	0	0	9
Lake	4,496	n/a	n/a	4,242	33	0	221
Lassen	2,538	n/a	n/a	56	0	0	2,482
Los Angeles	42,661	n/a	n/a	0	0	28,906	13,755
Madera	16	n/a	n/a	0	0	0	16
Marin	48	n/a	n/a	0	0	0	48
Mariposa	0	n/a	n/a	0	0	0	0
Mendocino	629	n/a	n/a	0	0	0	629
Merced	569	n/a	n/a	0	73	0	497
Modoc	1,324	n/a	n/a	292	0	0	1,033
Mono	7,845	n/a	n/a	560	45	6,246	993
Monterey	228	n/a	n/a	0	19	0	209
Napa	278	n/a	n/a	197	0	0	80
Nevada	67	n/a	n/a	0	0	0	67
Orange	452	n/a	n/a	0	0	0	452
Placer	76	n/a	n/a	0	0	0	76
Plumas	633	n/a	n/a	0	117	0	516
Riverside	33,843	n/a	n/a	0	0	25,348	8,495
Sacramento	4	n/a	n/a	0	0	0	4
San Benito	30	n/a	n/a	0	0	0	30
San Bernardino	111,278	n/a	n/a	378	0	75,978	34,922
San Diego	24,098	n/a	n/a	0	15	18,460	5,623
San Francisco	2	n/a	n/a	0	0	0	2
San Joaquin	824	n/a	n/a	0	0	0	824
San Luis Obispo	213	n/a	n/a	0	0	0	213
San Mateo	28	n/a	n/a	0	0	0	28
Santa Barbara	1,470	n/a	n/a	0	0	0	1,470
Santa Clara	26	n/a	n/a	0	14	0	12
Santa Cruz	10	n/a	n/a	0	8	0	2
Shasta	1,835	n/a	n/a	0	10	0	1,825
Sierra	280	n/a	n/a	0	80	0	200
Siskiyou	3,701	n/a	n/a	1,664	22	0	2,015
Solano	7,463	n/a	n/a	0	0	0	7,463
Sonoma	119	n/a	n/a	0	0	0	119

Table County-3.
Net Wind Resources Available
by County by Resources Class (MW)

CA County	Total Wind Resources	Wind Class 3	Wind Class 4	Wind Class 5	Wind Class 6	Wind Class 7
CA - Distributed	0	0	0	0	0	0
Alameda	40	40	0	0	0	0
Alpine	485	262	104	68	39	13
Amador	9	4	2	2	1	0
Butte	113	91	18	4	0	0
Calaveras	3	2	1	0	0	0
Colusa	82	68	14	0	0	0
Contra Costa	0	0	0	0	0	0
Del Norte	251	160	55	16	13	6
El Dorado	52	29	11	7	4	1
Fresno	193	156	35	2	0	0
Glenn	9	8	2	0	0	0
Humboldt	2,148	982	340	372	311	144
Imperial	8,514	5,913	1,745	420	268	169
Inyo	5,685	3,752	1,282	456	161	34
Kern	29,652	9,595	6,998	5,416	5,248	2,396
Kings	9	6	2	0	0	0
Lake	221	153	31	31	6	0
Lassen	2,482	1,699	541	120	89	34
Los Angeles	13,755	7,022	4,210	2,508	14	0
Madera	16	12	3	2	0	0
Marin	48	32	16	0	0	0
Mariposa	0	0	0	0	0	0
Mendocino	629	468	162	0	0	0
Merced	497	305	91	86	15	0
Modoc	1,033	564	179	143	106	41
Mono	993	597	204	135	48	10
Monterey	209	151	58	0	0	0
Napa	80	53	27	0	0	0
Nevada	67	46	18	2	1	0
Orange	452	270	162	14	4	1
Placer	76	48	19	5	3	1
Plumas	516	330	130	32	18	6
Riverside	8,495	5,603	1,654	1,239	0	0
Sacramento	4	3	1	0	0	0
San Benito	30	22	8	0	0	0
San Bernardino	34,922	24,279	7,166	1,703	1,087	687
San Diego	5,623	3,206	1,464	491	314	149
San Francisco	2	1	1	0	0	0
San Joaquin	824	636	189	0	0	0
San Luis Obispo	213	154	59	0	0	0
San Mateo	28	18	9	1	0	0
Santa Barbara	1,470	858	330	167	95	21
Santa Clara	12	8	4	0	0	0

Defining California Renewable Resource Zones

Based on E3's filtered resource potential estimates (described in the "New Generation Resource and Cost" reports) from NREL, the CEC, and other sources, California has a total of 53,044 MW of wind generation resource potential, 3,008 MW of geothermal potential, 221 MW of RPS-eligible small hydro potential, and 89,650 MW of CSP potential. Additionally, an estimated 300 MW of total biogas potential and 600 MW of total biomass potential exist in various locations across the state. Some of this resource potential is highly concentrated in certain areas and could be connected to the grid cost-effectively through large electricity transmission projects. Other portions of the total state-wide filtered potential are sparsely spread throughout more remote areas, causing them to be more expensive on a per-MW basis, especially when very large quantities of renewable resources must be added.

E3 began its definition of major areas of concentrated resource potential by a high-level comparison of resource-by-resource geography, taking into account excluded areas. This approach is illustrated in the following figures.

Figure 1. Major Areas of Geothermal Resource Potential

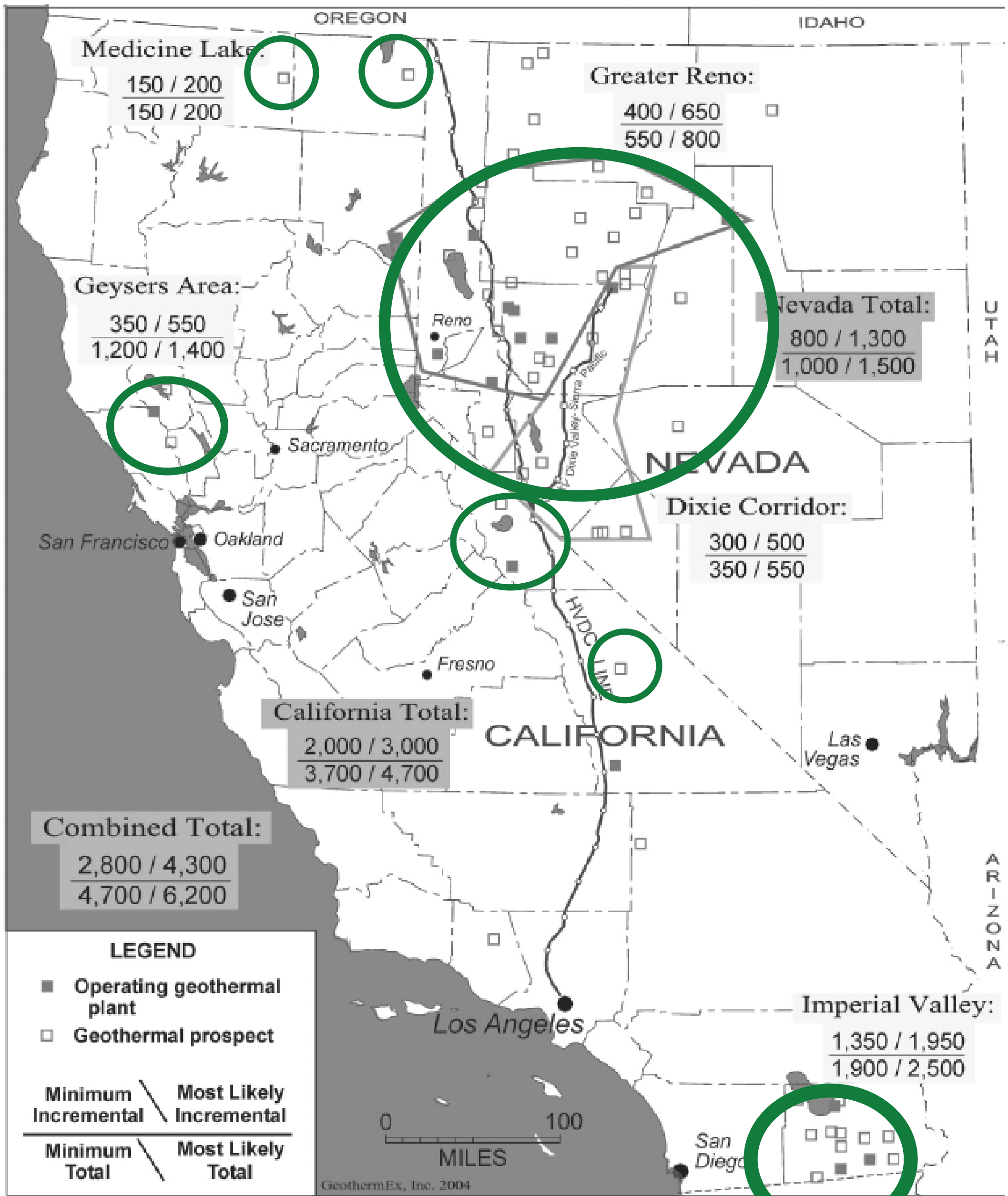
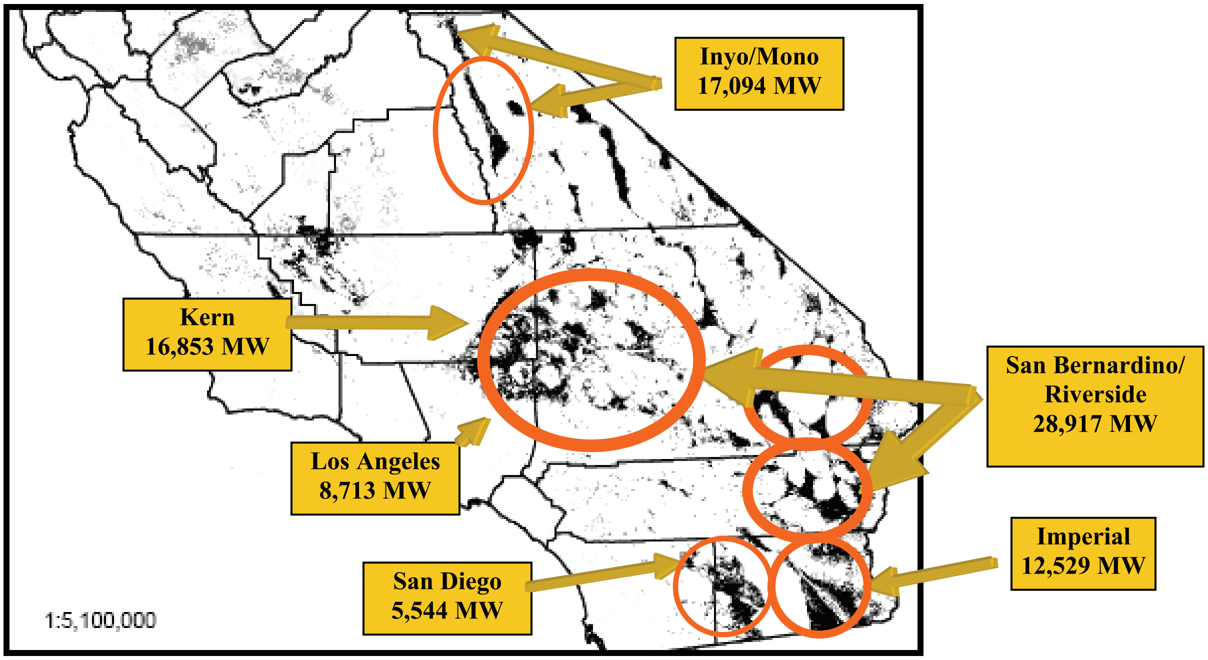


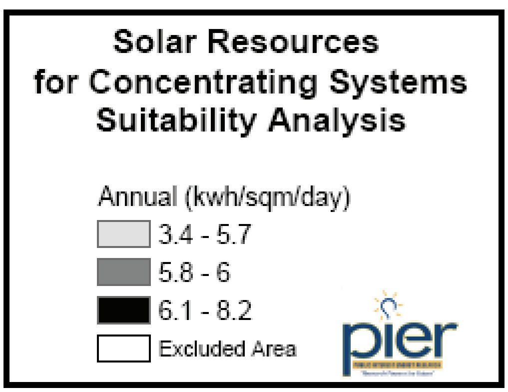
Figure 1 – Generation capacities of major geothermal resource areas in California and western Nevada (Gross M...

Source: Lovekin, Jim. Geothermex. "Geothermal Inventory," GRC Bulletin Nov/Dec 2004.

Figure 2. Major Areas of Solar Thermal Resource Potential – Excluded Areas Removed.

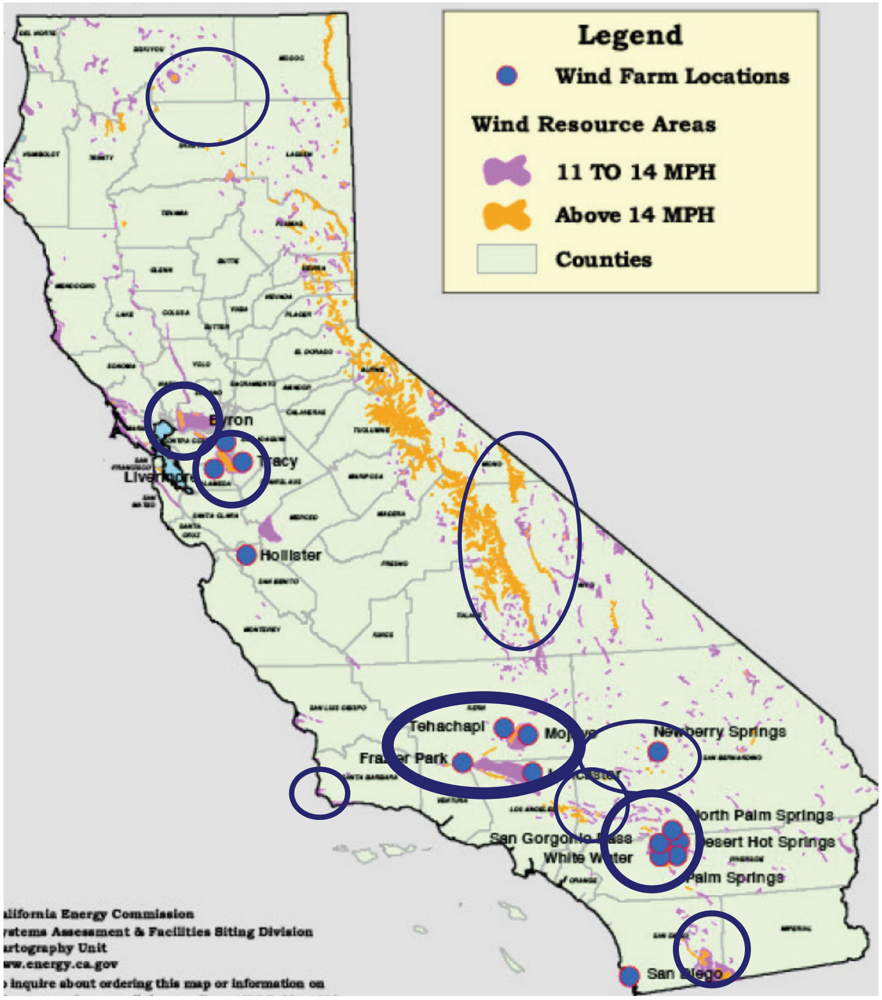


Source: CEC, Renewable Resources Development Report, 2005



Source: CEC, Renewable Resources Development Report, 2005

Figure 3. Major Areas of Wind Resource Potential, Minus Exclusion Areas.



Source: CEC Wind Resource Potential Map

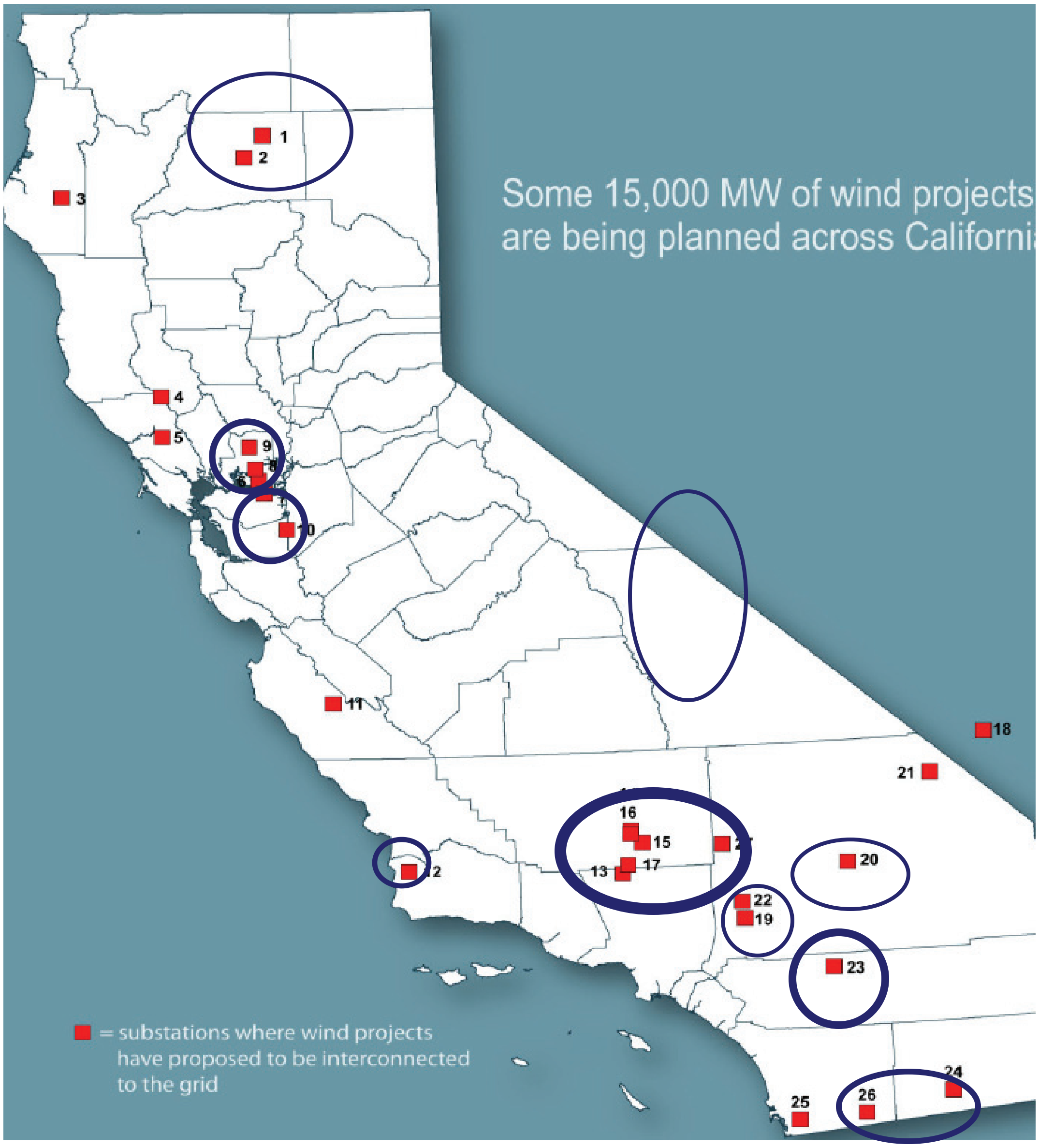


Figure 4. CALWEA map of proposed wind projects, overlaid with ovals indicating high wind potential zones.

Figure 5. Wind potential in southern California.

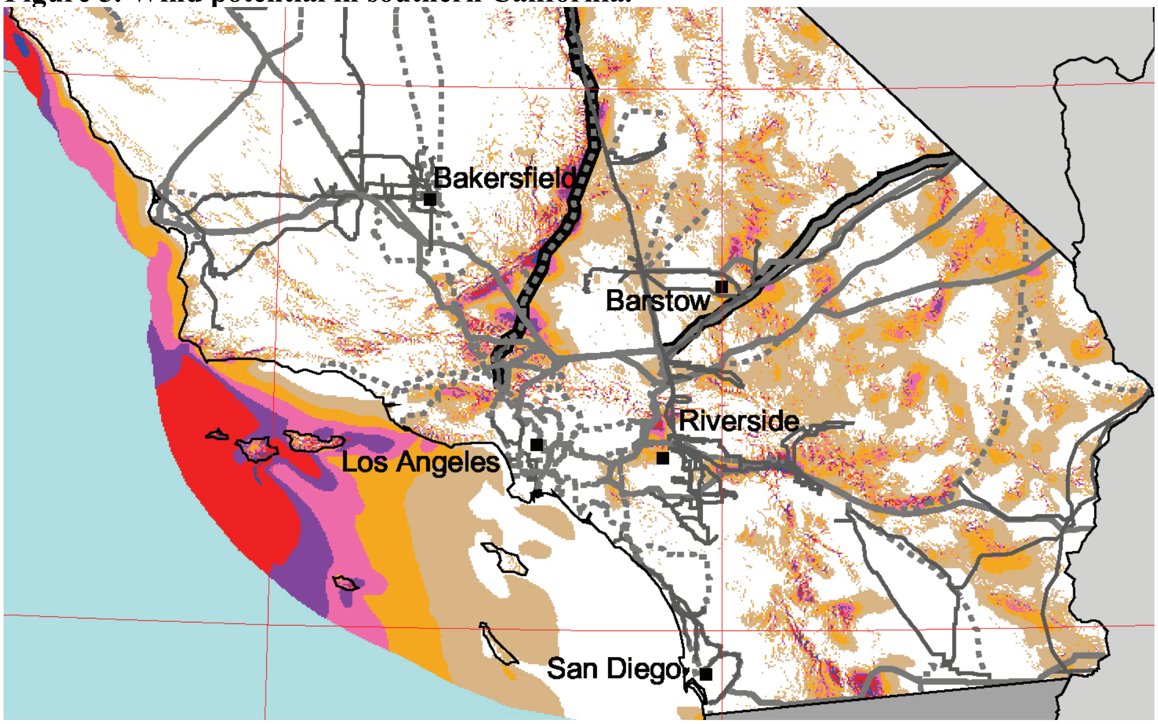
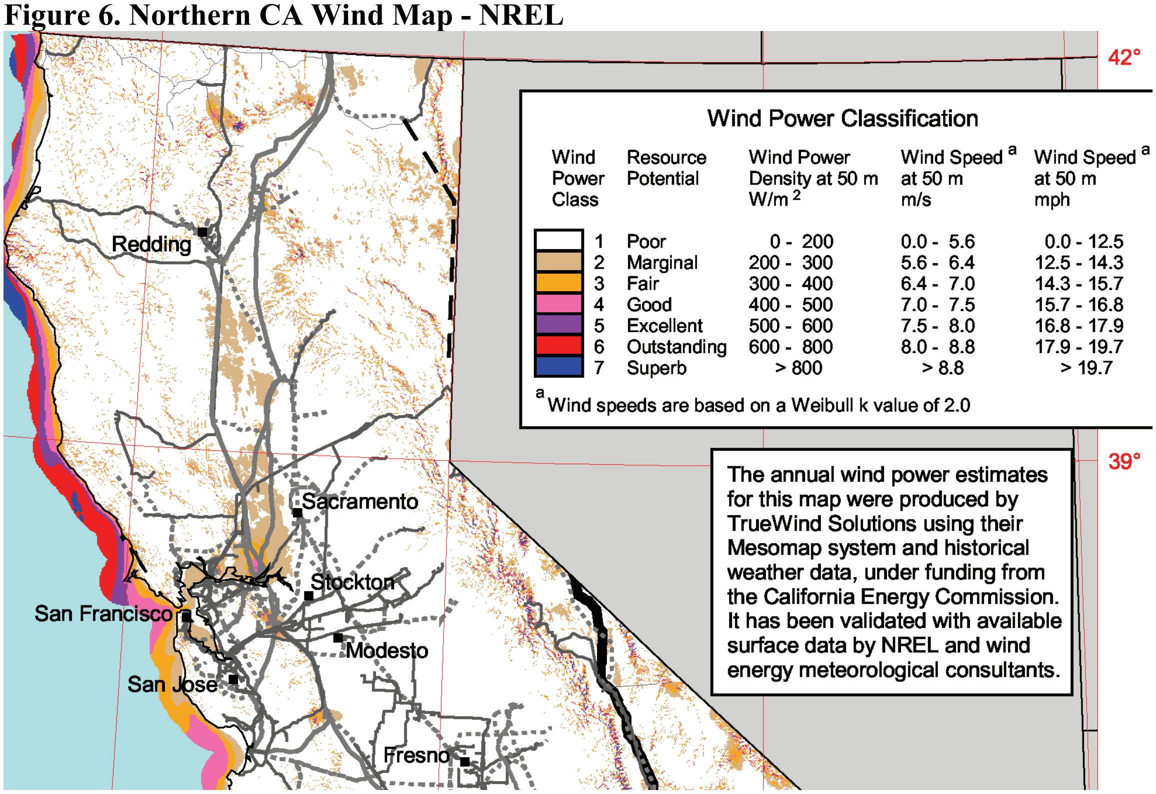


Figure 6. Northern CA Wind Map - NREL



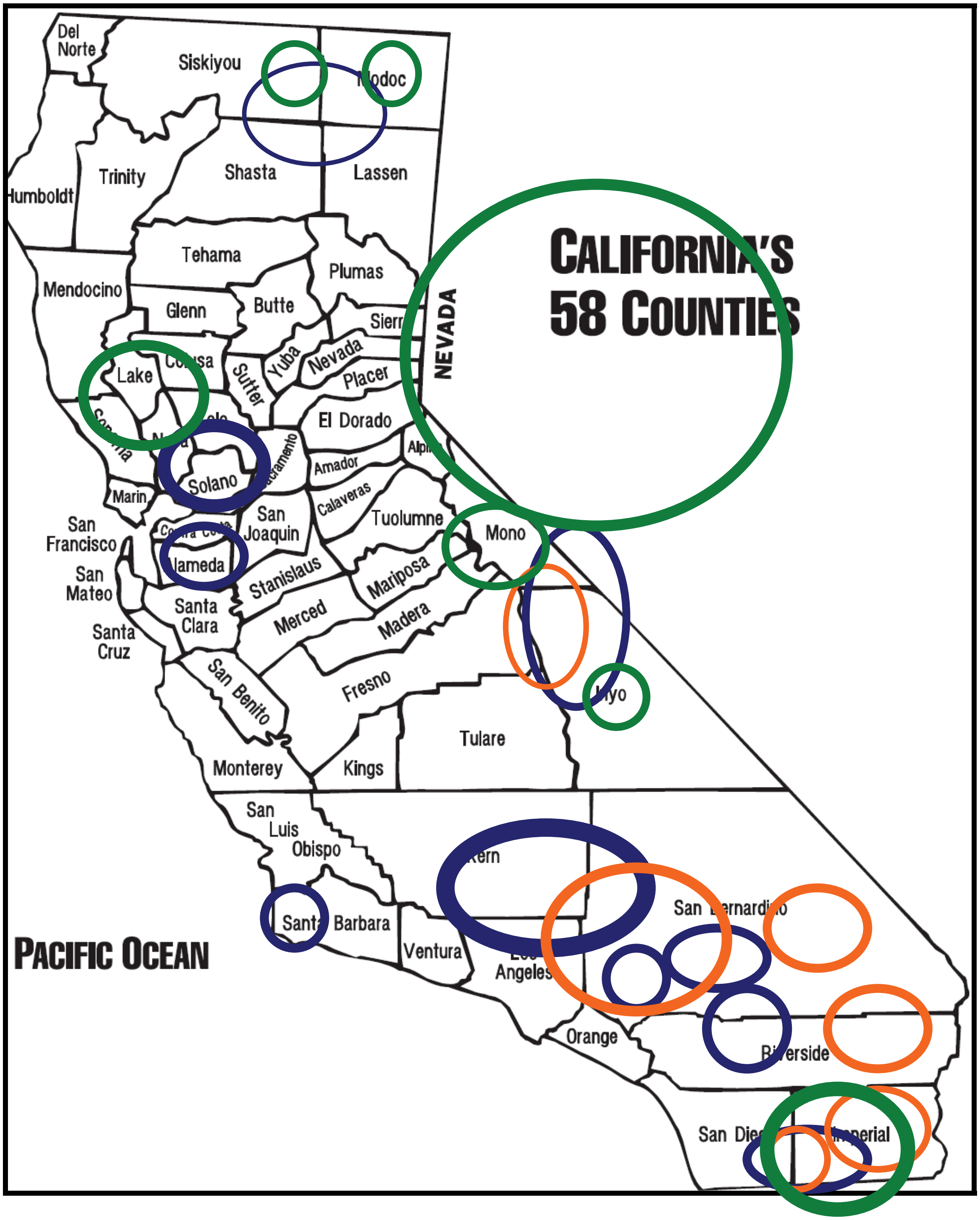


Figure 7. Indication of California renewable resource zones, based on comparison of high resource potential regions for wind, CSP, and geothermal. Key: Blue = wind, green = geothermal, orange = CSP.

Table County-5 below shows the mapping of the resource cluster areas identified in the high-level mapping process (see Figure 7 above) to California counties. This mapping forms the basis for allocation resources to California zones.

Table County-5:
Definition of Resource Cluster Territory

Resource Cluster	Territory Included in Cluster
CA - Distributed	Biomass and Biogas sites across CA
Bay Delta	Counties in CA: Alameda, Contra Costa, Marin, Solano
CFE	Renewbale potential in Baja California, Mexico: La Rumorosa, Mexicali, Ensenada, Tecate
Geysers/Lake	Counties in CA: Colusa, Lake, Sonoma
Imperial	Imperial County, CA
Mono/Inyo	Counties in CA: Inyo, Mono
NE NV	Counties in NV: White Pine, Elko (NREL Zone 36)
Northeast CA	Counties in CA: Lassen, Modoc, Shasta
Reno Area/Dixie Valley	Counties in NV: Carson City, Churchill, Douglas, Esmeralda, Eureka, Humboldt, Lander, Lyon, Mineral, Pershing, Storey, Washoe (NREL Zones 34, 35, 37)
Riverside	Riverside County, CA
San Bernardino	San Bernardino County, CA
San Diego	San Diego County, CA
Santa Barbara	Santa Barbara County, CA
Tehachapi	Kern County, CA

Tables CA-1 and CA-2 below show the renewable resource potential, in MW of capacity and GWh of energy, for the California zones (or resource clusters). These values are derived by aggregating the county level resources to the zonal level.

Table CA-1. Net Resources Available by Resource Cluster (MW)

Resource Cluster	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	300	600	0	0	0	0
Bay Delta	0	0	0	27	0	3,055
CFE	0	0	0	0	0	5,020
Geysers/Lake	0	0	538	11	0	170
Imperial	0	0	1,986	0	12,529	3,414
Mono/Inyo	0	0	151	18	17,094	2,661
NE NV	0	0	0	0	0	1,488
Northeast CA	0	0	255	8	0	2,931
Reno Area/Dixie Valley	0	0	1,316	0	7,449	3,230
Riverside	0	0	0	0	7,234	3,394
San Bernardino	0	0	48	0	21,683	14,007
San Diego	0	0	0	3	5,544	2,198
Santa Barbara	0	0	0	0	0	575
Tehachapi	0	0	0	0	16,853	10,755

Table CA-2. Net Resources Available by Resource Cluster (GWh)

Resource Cluster	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	2,102	4,205	0	0	0	0
Bay Delta	0	0	0	144	0	7,552
CFE	0	0	0	0	0	12,519
Geysers/Lake	0	0	4,242	33	0	422
Imperial	0	0	15,657	0	43,902	8,514
Mono/Inyo	0	0	1,190	95	57,403	6,678
NE NV	0	0	0	0	0	4,276
Northeast CA	0	0	2,011	32	0	7,354
Reno Area/Dixie Valley	0	0	10,374	0	24,287	9,254
Riverside	0	0	0	0	25,348	8,495
San Bernardino	0	0	378	0	75,978	34,922
San Diego	0	0	0	15	18,460	5,623
Santa Barbara	0	0	0	0	0	1,470
Tehachapi	0	0	0	0	58,285	29,652

Aggregating Resource Costs within Zones

Table CA-3 below shows the busbar levelized cost of energy by resource type within the California resource zones. These costs are based on the resource class specific data within each zone, and other costs detailed in the technology-specific cost reports and summarized in the "New Generation Cost Summary" report.

Table CA-3. Busbar Levelized Cost of Energy by Technology by Resource Cluster (2008 $/MWh)

Resource Cluster	Regional Multiplier	Biogas	Biomass	Geothermal	Hydro - Small	Solar Thermal	Wind
CA - Distributed	1.20	$91	$118	n/a	n/a	n/a	n/a
Bay Delta	1.20	n/a	n/a	n/a	$81 - $119	n/a	$74 - $101
CFE	1.00	n/a	n/a	n/a	n/a	n/a	$57 - $84
Geysers/Lake	1.20	n/a	n/a	$87 - $115	$176 - $177	n/a	$74 - $101
Imperial	1.20	n/a	n/a	$85 - $144	n/a	$128	$68 - $101
Mono/Inyo	1.20	n/a	n/a	$81 - $107	$88 - $220	$130 - $137	$68 - $101
NE NV	1.09	n/a	n/a	n/a	n/a	n/a	$62 - $80
Northeast CA	1.20	n/a	n/a	$81 - $103	$120 - $186	n/a	$68 - $101
Reno Area/Dixie Valley	1.09	n/a	n/a	$55 - $277	n/a	$119 - $125	$62 - $92
Riverside	1.20	n/a	n/a	n/a	n/a	$128	$68 - $101
San Bernardino	1.20	n/a	n/a	$92	n/a	$128	$68 - $101
San Diego	1.20	n/a	n/a	n/a	$107	$130 - $136	$68 - $101
Santa Barbara	1.20	n/a	n/a	n/a	n/a	n/a	$68 - $101
Tehachapi	1.20	n/a	n/a	n/a	n/a	$130	$68 - $101

33. Progress Note

Information on Nov. 7th Results

Since the September workshop, our project team has been working to put together the input data, methodology and analysis, GHG Calculator, and production simulation runs for the Stage 1 model results. We are making good progress, but the results are just that - a work in progress. This document describes the current state of progress in the GHG Modeling as of November 7th. We will continue to refine our analysis through our workshop on November 14th and look forward to working with you all to continue to refine this analysis in the stakeholder process. As we have noted on the website, we will make updated materials available as we have them ready.

Summary Results

The 'results' of the analysis are available as a set of summary tables from the current version of the GHG Calculator, as well as the GHG Calculator itself. This format provides the easiest way to 'update' the results when an input is refined.

As described in the methodology, we have developed two reference cases and a 'target' case for each. The two reference cases include a 'business as usual' reference case for 2020, and an 'aggressive policy' reference case for 2020. The target cases are designed to reach 100 MMt total emissions in 2020 for the electricity sector. The derivation of this target is described in another document. The target case for natural gas assumes 100% of economic potential of natural gas efficiency. At this level, natural gas emissions are still higher than the 1990 emissions levels. We did not assume that the electricity would make up the natural gas sector shortfall.

See *Business As Usual Results*
See *Aggressive Policy Results*

Spreadsheet Tool and Documentation

The result summary documents are based on tables from the GHG Calculator. The beta version of the GHG Calculator is posted on the E3 website. For most users, the necessary controls are provided on the 'Main' tab. This allows adjustments to the penetration levels of different resource options. For example, the level of development of renewables in a particular transmission cluster, or the achievements of energy efficiency programs. To provide a point of entry to the GHG Calculator, a high level summary of how to use the tool is provided. Both reference cases are included in a single spreadsheet, and a control is provided to switch between cases.

See *GHG Calculator Description*
See Beta *GHG Calculator Spreadsheet*

Progress on Modeling

The results presented in the analysis largely match the analysis presented at the September workshop. In a few areas, we have made short-cuts to complete the analysis on time. Most of the time saving measures were on documentation of the results, which we will continue to work on, however, the analysis components that have not been completed as of November 7th include the following.

- The simulation runs are done based on a zonal methodology rather than nodal.
- Demand response is not modeled in the simulation runs, but is included in the costs.
- Natural gas energy efficiency supply curves are based on Southern California Gas for all gas LSEs.

All of the other major components of the modeling have been completed, and will continue to be refined through the workshop and into Stage 2 of the project.

Next Steps

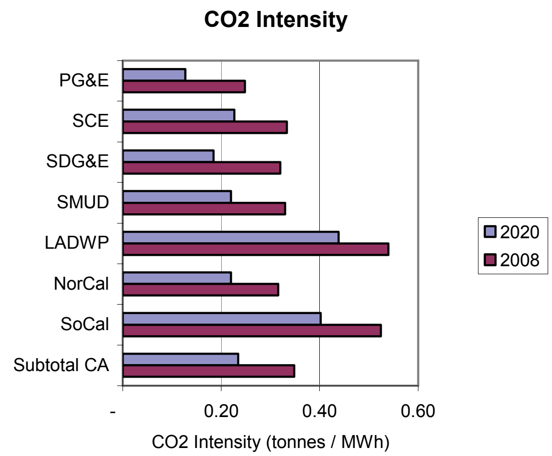
Before the November 14th workshop, our team is working three main tasks. The first is benchmarking the results to other studies, the second is refining the tool, and the third is developing workshop materials for the November 14th workshop. As materials are refined we will post new results and documents to the website, along with the revision number and date.

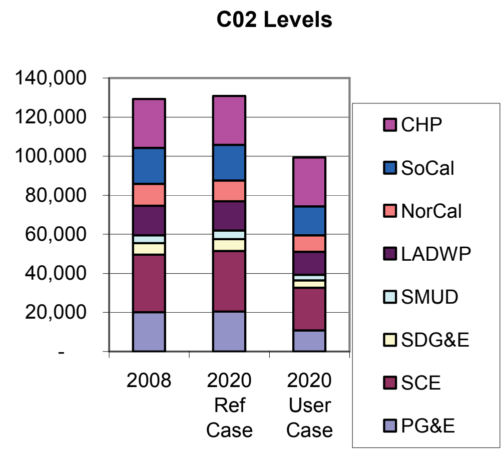
34. Business-as-Usual Model Results – Calculated in Metric Tonnes

The results shown below compare the 2020 'business-as-usual' reference case against a target case which approximates the greenhouse gas emissions of the electricity sector in 1990. For an explanation of the 'business-as-usual' case, see the summary paper on reference case policy assumptions. This is an illustrative example of the types of results which the E3 GHG calculator produces under a set of user-defined assumptions and does not reflect policy recommendations.

1. Summary of Greenhouse Gas Emission Results

Summary Results	Elec Gen	CHP	Total Elec	Gas	Total
Total CO2 in 2020 (kTonnes):	74,386	25,000	**99,386**	**57,350**	**156,736**
Reduction from 2008 (%):	29%	0%	**23%**	**-5%**	**15%**





GHG Emissions from the Electricity Sector by LSE in 2008 and 2020

Electricity Sector: **1000 tonnes CO2**

LSE	2008	2020 Ref Case	2020 User Case
PG&E	20,236	20,426	10,803
SCE	29,305	31,086	21,845
SDG&E	5,978	6,088	3,826
SMUD	3,924	4,410	2,787
LADWP	15,108	14,871	11,837
NorCal	11,281	10,660	8,441
SoCal	18,427	18,199	14,847
Subtotal CA	104,259	105,741	74,386
Non-CA WECC	263,021	316,937	316,937
Other Electric			
CHP	25,000	25,000	25,000
Total CA	129,259	130,741	99,386

GHG Emissions from the Natural Gas Sector by LSE in 2008 and 2020

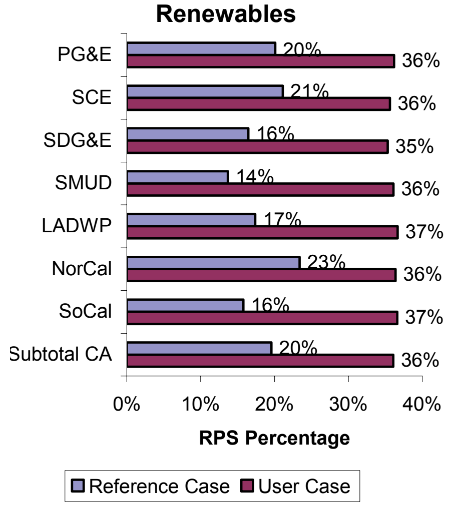
Natural Gas Sector: 1000 tonnes CO2

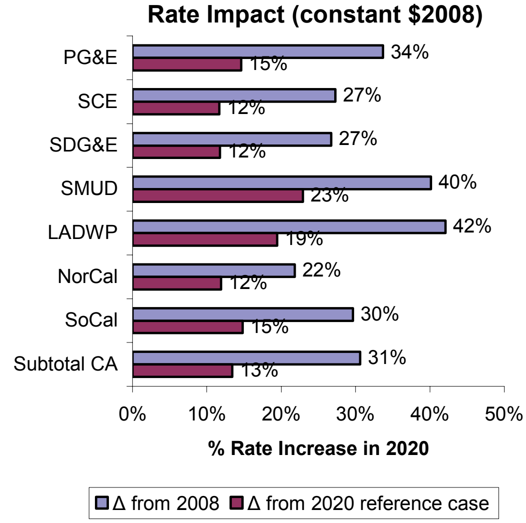
LSE	2008	2020 Ref Case	2020 User Case
PG&E	24,097	24,067	24,244
SoCalGas	26,744	28,433	29,160
Sempra	2,856	3,166	3,177
Other	697	769	769
Total CA	54,394	56,435	57,350

Summary of Cost in Business-as-Usual Case

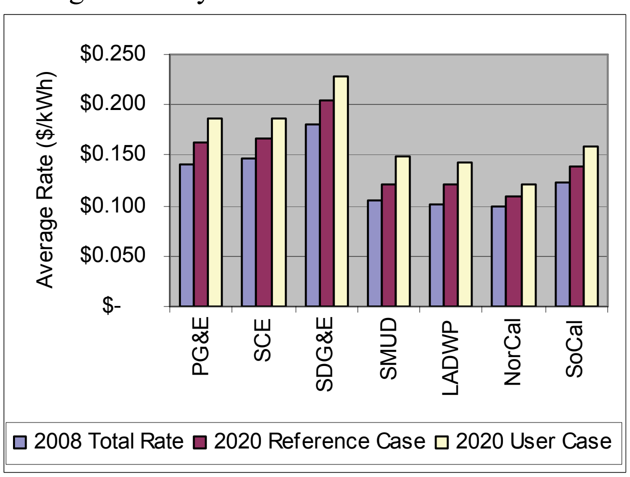
Incremental cost of user changes to Ref Case (Elec only) ($/tonne):	**149**
Incremental cost of user changes to Ref Case (Total) ($/tonne):	**155**

Renewable Percentage by LSE and Electricity Rate Impact by LSE





Average Rates by LSE in 2008 and 2020



2. Demand-Side Activities

Electric Energy Efficiency Results

Electric EE Assumptions - Penetration, Savings in 2020

	Target Case Achievement % of Economic	User Entered Achievement % of Economic	EE Program Spending $M/Year	GWh Savings for EE through 2020	MW Savings for EE through 2020	GWh Savings from gas EE through 2020	TRC Cost $/kWh
PG&E	25%	75%	$ 791	15,750	2,752	144	$ 0.076
SCE	31%	75%	$ 691	16,500	2,936	33	$ 0.063
SDG&E	34%	75%	$ 149	3,450	552	30	$ 0.065
SMUD	14%	75%	$ 63	1,596	261	-	$ 0.059
LADWP	31%	75%	$ 185	4,425	787	-	$ 0.063
NorCal	24%	75%	$ 75	1,500	262	2	$ 0.076
SoCal	31%	75%	$ 94	2,250	400	4	$ 0.063
CA Subtotal			2,049	45,471	7,952	212	

Natural Gas Energy Efficiency Results

Natural Gas EE Assumptions - Penetration, Savings in 2020

	Target Case Achievement % of Economic	User Entered Achievement % of Economic	EE Program Spending $M/Year	MMTh Savings for gas EE	MMTh Savings from Elec EE	CO2 Savings
PG&E	45%	45%	$ 40	154.9	80.0	(195)
SoCalGas	38%	38%	$ 3	(22.1)	24.7	(802)
Sempra	48%	48%	$ 10	23.5	4.2	(11)
Other	50%	50%	$ 2	4.5	-	-
Total			$ 55	160.8	108.9	(1,008)

California Solar Initiative and Demand Response Results

CSI and Demand Response

	Reference Case	User Case
CSI Nameplate MW	1091	1,091
DR in 2020 (% of Peak)	5%	5%

Note: No market transformation is assumed in this case.

3. Incremental Generation to California 2008 – 2020

Renewable Resources Added by Area

Renewable resources by transmission cluster	Total Renewable Resources (MW)	Cap Factor of all Resources in Cluster	Target Case Starting MW	User Selelected MW	Cost of Next increment	Rank (Lowest to Highest)
1 Alberta	5,386	27%	-	-	153	17
2 Arizona-Southern Nevada	5,948	38%	-	-	527	24
3 Bay Delta	2,991	28%	-	-	132	12
4 British Columbia	4,093	43%	-	-	173	18
5 CA - Distributed	900	80%	-	900	113	2
6 CFE	5,020	28%	-	2,000	128	8
7 Colorado	5,545	35%	-	-	445	23
8 Geysers/Lake	719	75%	-	719	118	3
9 Imperial	6,000	55%	2,500	5,500	123	5
10 Mono/Inyo	5,825	40%	-	-	122	4
11 Montana	5,632	38%	-	-	133	13
12 NE NV	1,444	33%	-	-	139	16
13 New Mexico	5,736	35%	-	-	138	15
14 Northeast CA	3,194	34%	404	404	104	1
15 Northwest	5,764	42%	-	-	236	21
16 Reno Area/Dixie Valley	5,825	45%	-	4,000	124	6
17 Riverside	6,000	39%	-	1,000	130	11
18 San Bernardino	5,825	36%	-	2,000	128	9
19 San Diego	6,000	37%	-	500	126	7
20 Santa Barbara	576	29%	-	-	134	14
21 South Central Nevada	5,978	39%	-	-	303	22
22 Tehachapi	5,825	34%	4,369	4,369	129	10
23 Utah-Southern Idaho	5,797	46%	-	-	198	20
24 Wyoming	5,613	40%	-	-	180	19

Ownership of Incremental Renewable Generation by LSE

	Target case default values	Allocation of renewables to LSEs	
PG&E	24.0%	27.0%	Note:
SCE	25.0%	27.0%	If owned or contracted generation plus assigned
SDG&E	9.5%	7.5%	renewables exceeds an LSEs energy requirements,
SMUD	8.0%	5.5%	excess renewables will displace pool energy.
LADWP	11.5%	10.0%	Net cost to the LSE will equal difference between
NorCal	4.0%	9.0%	renewable cost and pool price.
SoCal	18.0%	14.0%	
Subtotal CA		100.0%	

New low carbon and conventional generation added

Emerging low carbon and conventional generation

	Target Case Starting MW	User Selelected MW
Coal IGCC	-	-
Coal IGCC with CCS	-	-
Coal ST	-	-
Gas CCCT	-	-
Gas CT	6,371	6,371
Nuclear	-	-
Tar Sands	-	-
Total	6,371	6,371

Natural Gas and Coal Price Assumptions

	Gas in CA	Coal in WY
Fuel Price in 2008 ($/MMBTU)	$ 6.50	$ 0.84
Base Case Costs in 2008 $'s	$ 6.53	$ 0.84

Plant Capacity Added or Removed to Balance Energy and Peak Demand

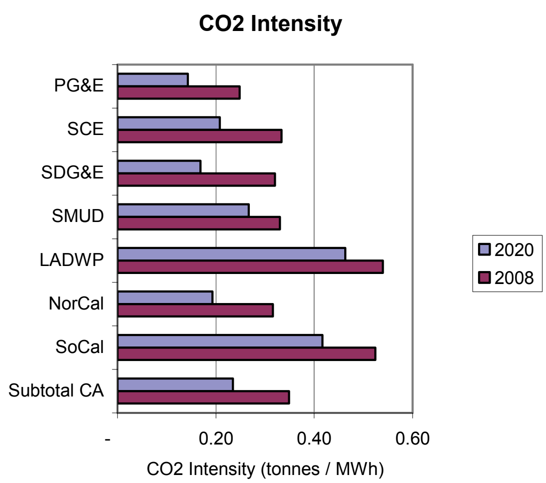
	CCGT	CT
CA Subtotal	(14,307)	3,728

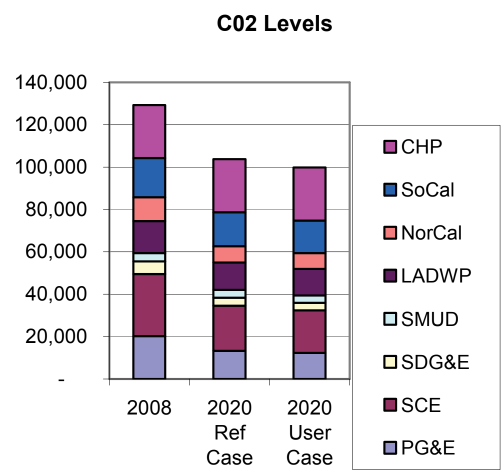
35. Aggressive Policy Model Results – Calculated in Metric Tonnes

The results shown below compare the 2020 'aggressive-policy' reference case against a target case which approximates the greenhouse gas emissions of the electricity sector in 1990. For an explanation of the 'aggressive-policy' case, see the summary paper on reference case policy assumptions. This is an illustrative example of the types of results which the E3 GHG calculator produces under a set of user-defined assumptions and does not reflect policy recommendations.

4. Summary of Greenhouse Gas Emission Results

Summary Results	Elec Gen	CHP	Total Elec	Gas	Total
Total CO2 in 2020 (kTonnes):	74,804	25,000	**99,804**	**55,695**	**155,499**
Reduction from 2008 (%):	28%	0%	**23%**	**-2%**	**15%**





GHG Emissions from the Electricity Sector by LSE in 2008 and 2020

Electricity Sector:	**1000 tonnes CO2**		
LSE	2008	2020 Ref Case	2020 User Case
PG&E	20,236	13,348	12,263
SCE	29,305	21,224	20,216
SDG&E	5,978	3,846	3,523
SMUD	3,924	3,592	3,386
LADWP	15,108	12,979	12,604
NorCal	11,281	7,743	7,404
SoCal	18,427	15,990	15,407
Subtotal CA	104,259	78,721	74,804
Non-CA WECC	263,021	305,681	305,681
Other Electric			
CHP	25,000	25,000	25,000
Total CA	129,259	103,721	99,804

GHG Emissions from the Natural Gas Sector by LSE in 2008 and 2020

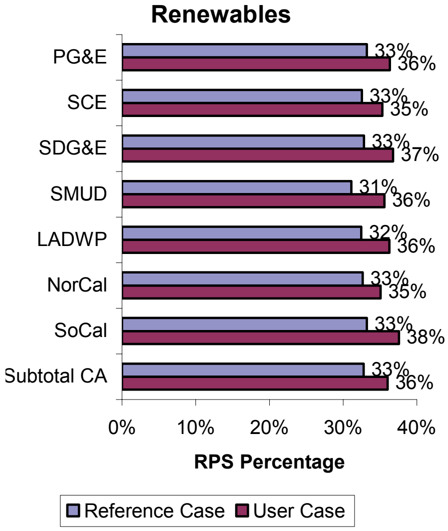
Natural Gas Sector: 1000 tonnes CO2

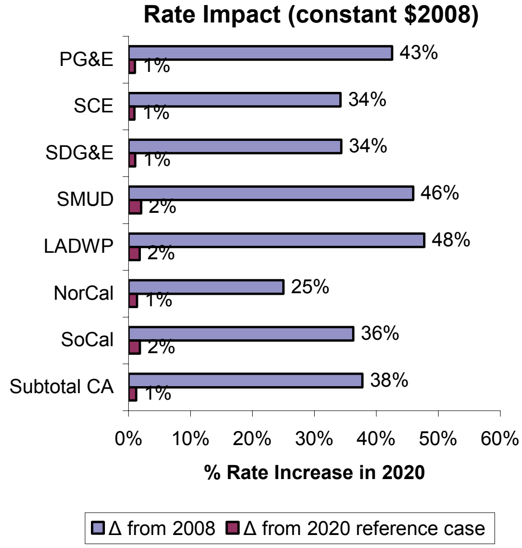
LSE	2008	2020 Ref Case	2020 User Case
PG&E	24,097	22,598	23,209
SoCalGas	26,744	27,761	28,774
Sempra	2,856	2,949	2,979
Other	697	733	733
Total CA	54,394	54,042	55,695

Summary of Cost

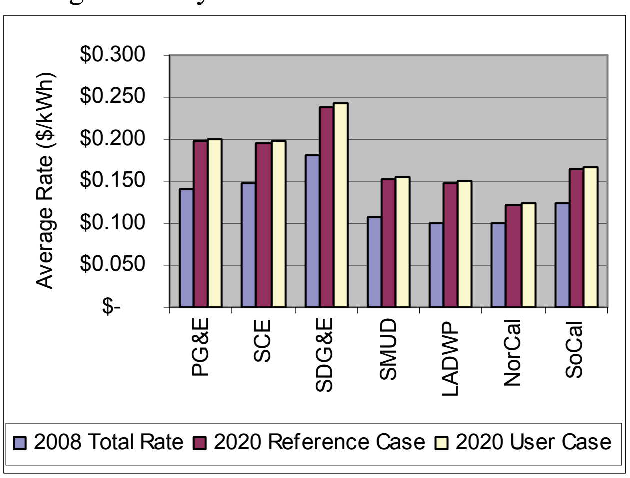
Incremental cost of user changes to Ref Case (Elec only) ($/tonne):	**165**
Incremental cost of user changes to Ref Case (Total) ($/tonne):	**362**

Renewable Percentage by LSE and Electricity Rate Impact by LSE





Average Rates by LSE in 2008 and 2020



5. Demand-Side Activities

Electric Energy Efficiency Results

Electric EE Assumptions - Penetration, Savings in 2020

	Target Case Achievement % of Economic	User Entered Achievement % of Economic	EE Program Spending $M/Year	GWh Savings for EE through 2020	MW Savings for EE through 2020	GWh Savings from gas EE through 2020	TRC Cost $/kWh
PG&E	100%	100%	$ 1,177	21,000	3,670	287	$ 0.080
SCE	100%	100%	$ 1,028	22,000	3,915	88	$ 0.067
SDG&E	100%	100%	$ 221	4,600	737	60	$ 0.069
SMUD	100%	100%	$ 93	2,128	348	-	$ 0.063
LADWP	100%	100%	$ 276	5,900	1,050	-	$ 0.067
NorCal	100%	100%	$ 112	2,000	350	5	$ 0.080
SoCal	100%	100%	$ 140	3,000	534	7	$ 0.067
CA Subtotal			3,048	60,628	10,603	447	

Natural Gas Energy Efficiency Results

Natural Gas EE Assumptions - Penetration, Savings in 2020

	Target Case Achievement % of Economic	User Entered Achievement % of Economic	EE Program Spending $M/Year	MMTh Savings for gas EE	MMTh Savings from Elec EE	CO2 Savings
PG&E	80%	80%	$ 118	350.0	106.6	(673)
SoCalGas	60%	60%	$ 18	50.6	32.9	(1,117)
Sempra	93%	93%	$ 30	60.8	5.6	(33)
Other	100%	100%	$ 6	11.3	-	-
Total			$ 171	472.7	145.2	(1,823)

California Solar Initiative and Demand Response Results

CSI and Demand Response

	Reference Case	User Case
CSI Nameplate MW	3000	3,000
DR in 2020 (% of Peak)	5%	5%

Note: No market transformation is assumed in this case.

6. Incremental Generation to California 2008 – 2020

Renewable resources by transmission cluster

	Total Renewable Resources (MW)	Cap Factor of all Resources in Cluster	Target Case Starting MW	User Selelected MW	Cost of Next increment	Rank (Lowest to Highest)
1 Alberta	5,386	27%	-	-	153	17
2 Arizona-Southern Nevada	5,948	38%	-	-	527	24
3 Bay Delta	2,991	28%	-	-	132	10
4 British Columbia	4,093	43%	-	-	173	18
5 CA - Distributed	900	80%	232	900	113	3
6 CFE	5,020	28%	2,163	2,163	130	7
7 Colorado	5,545	35%	-	-	445	23
8 Geysers/Lake	719	75%	719	719	119	6
9 Imperial	6,000	55%	2,500	3,000	111	2
10 Mono/Inyo	5,825	40%	243	243	138	14
11 Montana	5,632	38%	-	-	133	11
12 NE NV	1,444	33%	-	-	139	16
13 New Mexico	5,736	35%	-	-	138	15
14 Northeast CA	3,194	34%	1,000	1,000	118	5
15 Northwest	5,764	42%	-	-	236	21
16 Reno Area/Dixie Valley	5,825	45%	1,942	2,500	117	4
17 Riverside	6,000	39%	2,000	2,000	134	12
18 San Bernardino	5,825	36%	-	-	105	1
19 San Diego	6,000	37%	750	750	130	8
20 Santa Barbara	576	29%	-	-	134	13
21 South Central Nevada	5,978	39%	-	-	303	22
22 Tehachapi	5,825	34%	4,369	5,000	131	9
23 Utah-Southern Idaho	5,797	46%	-	-	198	20
24 Wyoming	5,613	40%	-	-	180	19

Ownership of Incremental Renewable Generation by LSE

	Target case default values	Allocation of renewables to LSEs	
PG&E	26.0%	26.0%	Note:
SCE	26.0%	26.0%	If owned or contracted generation plus assigned
SDG&E	8.0%	8.0%	renewables exceeds an LSEs energy requirements,
SMUD	5.5%	5.5%	excess renewables will displace pool energy.
LADWP	10.0%	10.0%	Net cost to the LSE will equal difference between
NorCal	9.0%	9.0%	renewable cost and pool price.
SoCal	15.5%	15.5%	
Subtotal CA		100.0%	

No emerging low carbon or new conventional generation is added in this case.

Natural Gas and Coal Price Assumptions

	Gas in CA	Coal in WY
Fuel Price in 2008 ($/MMBTU)	$ 6.50	$ 0.84
Base Case Costs in 2008 $'s	$ 6.53	$ 0.84

Plant Capacity Added or Removed to Balance Energy and Peak Demand

	CCGT	CT
CA Subtotal	(1,765)	758

36. Electricity Sector Emissions Benchmark for 1990 and 2004

Table 1 below shows all GHG emissions for which the electricity sector was responsible in 1990 and 2004, taken from the August 22, 2007 version of the CARB GHG emissions inventory. There are four categories of emissions: electricity generation, CHP, fugitive SF_6 from electricity T&D, and fugitive CO_2 from geothermal generation. All types of emissions are included: CO_2, CH_4, and N_2O. Both in-state and import emissions are included. The total is 123.9 MMT in 2004 and 100.1 in 1990. The calculation of emissions in the GHG Calculator reflects all of these categories and types of emissions.

Table 1. Electricity Sector Emissions in 1990 and 2004, from CARB Inventory

Million metric tons CO2 equivalent			
Activity	**Source**	**1990 Emissions**	**2004 Emissions**
Total electricity sector responsibility		**100.07**	**123.92**
Electricity Generation	Total	**82.12**	**100.10**
	Import Specified	25.95	33.48
	Import Unspecified	26.25	35.36
	In State Merchant	1.32	25.80
	In State Utility	28.61	5.45
CHP	Total	**15.14**	**22.46**
	Electric	8.01	12.15
	Commercial	0.73	0.83
	Industrial	6.40	9.49
SF6 from electrical T&D	Total	**2.429**	**1.029**
	In State Generation Not Specified	1.509	0.669
	Imported Electricity Not Specified	0.920	0.360
Geothermal fugitive emissions	Total	**0.373**	**0.333**
	Merchant	0.157	0.307
	Utility	0.217	0.027

37. Natural Gas Emissions Benchmark for 1990 and 2004

Table 2 below shows the 1990 (target) and 2004 (proxy for 2008) emissions for the natural gas sector, based on the 8/22/07 CARB inventory. The total emissions are 53.1 MMT for 1990 and 52.4 MMT for 2004.

The emissions include all non-power generation and non-CHP use of natural gas by all end users, both utility and non-utility customers, including industrial, commercial, residential, and agricultural sectors. Also included are pipeline combustion of natural gas, and fugitive emissions of CH_4.

Table 2. Natural Gas Sector Emissions in 1990 and 2004, from CARB inventory

Million metric tons CO2 equivalent		
	1990 Emissions	**2004 Emissions**
Total emissions from natural gas sector	**53.12**	**52.41**
Natural Gas Combustion (not for electricity generation or CHP)	**50.94**	**50.38**
Manufacturing & Construction	11.98	9.79
Commercial/ Institutional	10.69	13.18
Residential	27.73	26.68
Agriculture	0.54	0.73
Pipeline combustion	**0.67**	**0.67**
Natural Gas pipeline fugitive emissions	**1.50**	**1.35**

38. 2008 Benchmarking (Forthcoming)

39. 2020 Benchmarking (Forthcoming)

40. GHG Calculator v.1a Reference

This reference guide provides a high level summary of the GHG Calculator. The intent is to provide a reference for users of the tool who are interested in evaluating their own cases. Due to time constraints, the explanation is limited to the controls on the Main tab of the spreadsheet. The reference guide will be updated periodically to reflect changes in the Calculator.

Table of Contents

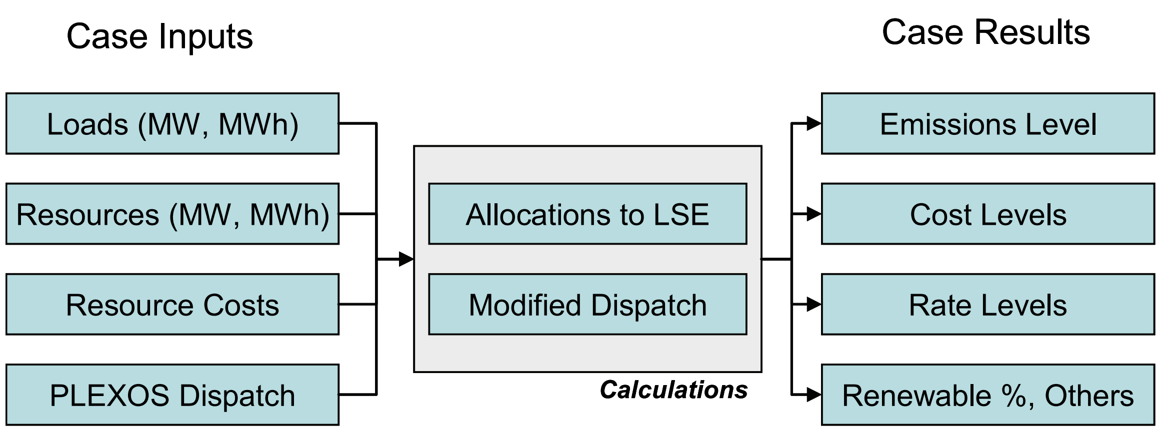
Analysis Structure

The GHG Calculator is designed to help the analyst estimate emissions levels and utility costs in 2020 for different scenarios. The fundamental building block is a 'case' which includes all of the input assumptions required to calculate emissions levels, costs, and other metrics by load serving entity (LSE) for a single possibility in 2020. The GHG Calculator also facilitates the comparison between cases, and reports changes in emissions, costs, and other metrics between them.

Definition of a Case

The inputs, calculations, and results in the GHG Calculator that define a 2020 'case' are illustrated in Figure 7, below. At a high level the inputs include assumptions about loads, resources to meet load, resource costs, and system dispatch. With these inputs the GHG Calculator computes results for that case. In order to calculate the results, summary analysis from the production simulation model PLEXOS has been input into the analysis tool and is automatically modified in the spreadsheet depending on changes to the resources and loads. In addition, responsibility for emissions and costs are assigned to Load Serving Entity (LSE) so that LSE-specific outputs can be calculated. The case 'results' include emissions levels, costs, rates, and other metrics such as renewable energy percentage.

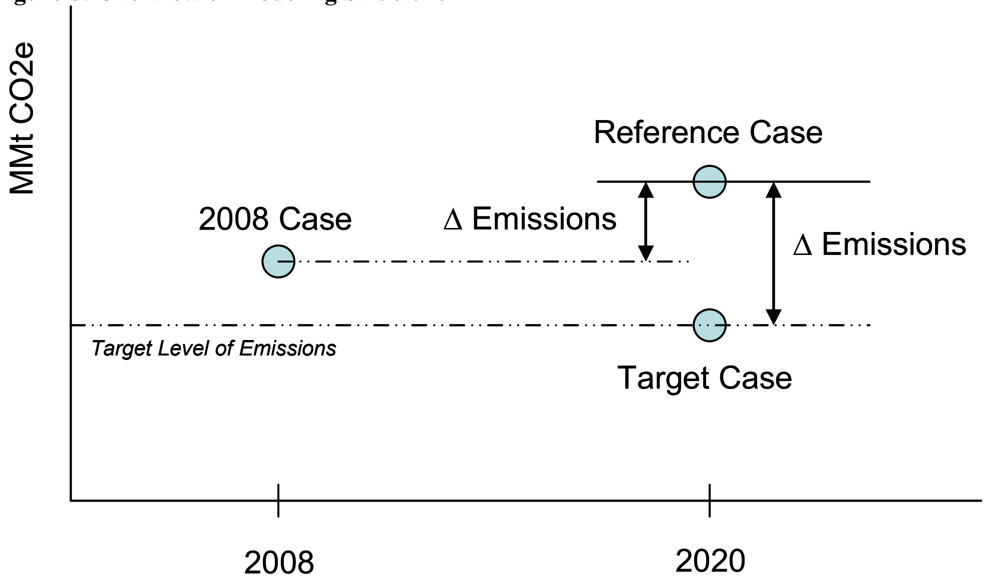
Figure 7: Inputs, Calculation, and Results of a GHG Calculator Case



Comparison of Cases

In order to provide a reference for changes to emissions levels and costs in 2020, our methodology defines a reference case and a target case. The reference case is a projection of 2020 under a set of policy assumptions, and the target case includes additional low-carbon resources to meet a specified level of CO_2 emissions. The reference case and target case are then compared to provide differences in emissions levels as illustrated in Figure 8, below. Using the tool, the analyst can modify the target case developed by E3 to create their own target case. This is labeled in the model as the 'user defined' case. As an additional point of reference, the GHG calculator also computes the difference between a 2008 case to comparison to current costs, rates, and emissions. Similarly, differences in costs, rate levels, and other metrics are also calculated.

Figure 8: Overview of Modeling Structure



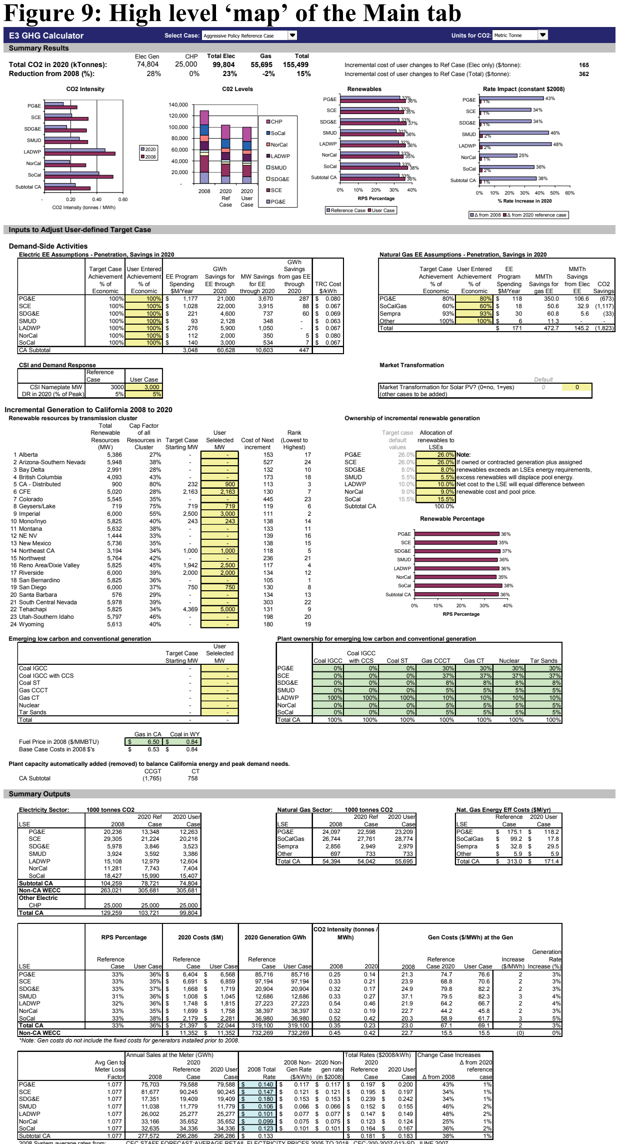
In the current version of the GHG Calculator, two pairs of cases have been developed. The first is a 'Business As Usual' reference and target case and the second is an 'Aggressive Policy' reference and target case. A control on the 'Main' tab allows the analyst to change between the cases.

Main Tab

For most users, the 'Main' tab will control the analysis of the model. From this tab, the analyst can select the pair of reference case, target case they would like to modify, and then modify the target case with different levels of resources, and allocation of resources between LSEs. Once an analysis is complete, the Main tab is formatted to print out the summary inputs and results on two pages (front and back).

Figure 9, below, is an illustration shows at a high level how the Main tab is organized. There are three sections; (1) the title bar and graphical results, (2) input assumptions, and (3) high level results. Each section is described in this section.

Figure 9: High level 'map' of the Main tab



Title Bar
•Select Reference / Target Case Pair
•Specify CO2e units
•View emissions levels of CO2
•View quick charts on results

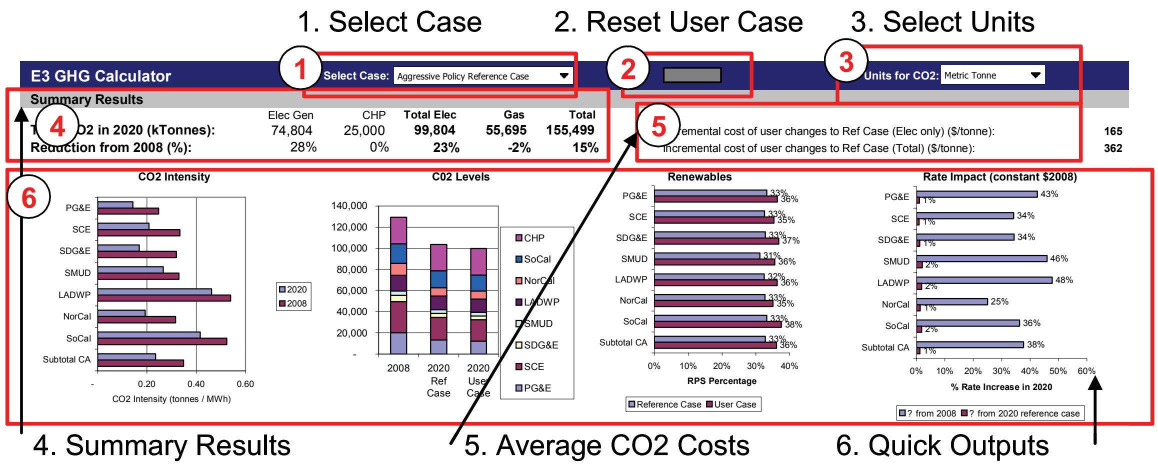
Inputs
•Specify Electric EE Penetration
•Specify Natural Gas EE Penetration
•Specify CSI Penetration
•Specify DR Penetration
•Specify Renewable Resources
•Specify Low-carbon Resources
•Specify Allocation of Renewables

Outputs by LSE and Statewide
Electricity CO2 Emissions by LSE
Natural Gas Emissions by LSE
RPS Achievements
Generated Energy
Carbon Intensity
Generation Costs
Change in Rates

Title Bar

The Main tab title bar, illustrated in Figure 10 below, allows the analyst to select the reference case and target cases that have been defined by E3, adjust the units of CO2e, view the total emissions by sector for each case, and view the quick graphical summaries by result.

Figure 10: Main Tab Title Bar



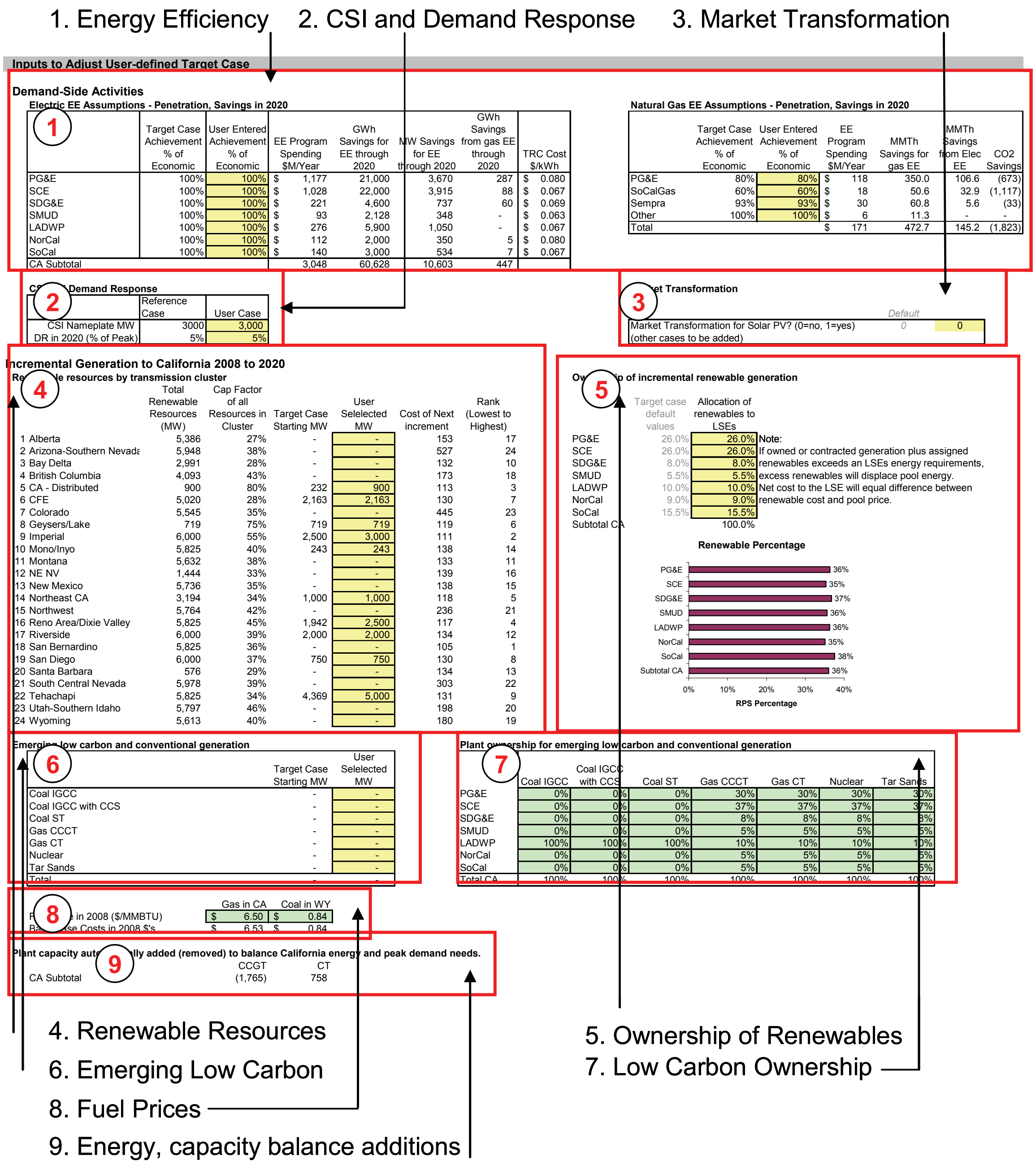
1. **Select Case**: Drop down allows selection between Business As Usual and Aggressive Policy cases. When you select this drop down, the model will load both the reference case and the E3 defined target case.
2. **Reset User Case Button**: Allows user to clear their user defined case and reset the inputs on the Main tab so that the 'user case' matches the E3-defined target case. Note that this only changes the inputs on the Main tab, it does not reset inputs that may have changed on other tabs.
3. **Select Units**: Changes the units between metric tonnes and short tons
4. **Summary Results**: Shows the total emissions for the sector in the 'user defined' case. The CO2 emissions levels are presented in fixed pane so that the user can see the CO2 emissions levels as other inputs on the Main tab are adjusted by the analyst.
5. **Average CO2 Costs**: Shows the average costs of CO2 reduction. This is calculated in two ways;
   - **Incremental cost of user changes to Ref Case (Elec only) ($/tonne)**: shows the change in electric costs divided by the change in CO2 emissions between the 2020 reference case and the 2020 user defined case for the electric sector.
   - **Incremental cost of user changes to Ref Case (Total) ($/tonne)**: shows the change in total gas and electric sector costs divided by the change in total gas and electric CO2 emissions between the 2020 reference case and the 2020 user defined case.
6. **Quick Outputs**: Provides four small graphical summaries of the results

- **Carbon Intensity by LSE and CA**: Shows the emissions per MWh for each LSE based on the allocation of resources to utilities as well as the overall CA emission intensity per MWh for the 2008 case and the 2020 user-defined case.
- **Electric-sector Carbon Levels for the (a) 2008 Case, (b) Reference Case, and (c) User Case**: Shows the total emissions in the electricity sector for each of the three cases.
- **Renewable Energy Percentage by LSE**: Shows the renewable purchases for each LSE as a percentage of retail sales in the 2020 reference case and the 2020 user-defined case.
- **Rate Impacts by LSE**: Shows the estimated retail rate impact in real terms by LSE as a change from 2008 and as a change between the reference case and the user defined case in 2020. For example, the change from 2008 is compared as the rate level in 2008 in $2008 dollars compared to the rate level in 2020 in $2008 dollars. This means that if the rate change is 0% (zero) percent, rates will rise with the assumed inflation rate between 2008 and 2020.

Inputs

The inputs on the Main tab, as illustrated in Figure 11 below, control the resources for the 'user defined' case, as well as fuel costs and allocations of new resources to LSE.

Figure 11: Main Inputs



1. **Energy Efficiency**: Specify the penetration level of both electricity and natural gas energy efficiency in 2020 as a percentage of the estimated 2020 economic potential. A penetration level of 100% of economic potential is roughly equivalent to the utility goals

set by the CPUC or CEC AB2021 process after adjusted by net to gross ratio. For each level defined, the costs and impacts of energy efficiency are shown based on an energy efficiency supply curve approach.

2. **CSI and Demand Response:** Specify the statewide penetration of CSI in nameplate MW, and demand response penetration as a percentage of system peak. For CSI the GHG Calculator assumes that the MW are divided among the investor-owned utilities in proportion to MW allocation to each utility in the CSI program. For demand response, DR resources are divided among all electric utilities (IOU and public) based on their share of the system peak.

3. **Market Transformation**: Specify whether or not to include market transformation effects for CSI. Enter a '1' to include market transformation, '0' not to include market transformation assumptions. This input only affects customer-costs, not utility costs so will not affect the results seen on the Main tab. This feature is also placeholder for a sensitivity analysis for central station generation resources as well.

4. **Incremental Renewable Generation**: Specify the nameplate MW to be developed for each of the transmission clusters identified throughout the WECC. The clusters include many zones in California, and broader zones outside of California. If an amount greater than 0 (zero) is defined for a cluster, the model includes costs of transmission to deliver the energy to California as well as the costs of resources, and integration costs. In addition to integration costs, firming costs for capacity are added to the model based on the portfolio capacity balance (see #9 below). For each zone, E3 has developed a supply curve for the least cost renewables in each zone and the model will assume that they are developed in economic order.

5. **Ownership of Incremental Renewable Generation**: Specify the allocation of the renewable resources to LSE. To aid the analyst in the assignment, the RPS energy shares are shown in the chart below the allocation. The model assigns the same mix of incremental renewables to each LSE (both high cost and low cost). Therefore, all LSEs have the same cost of incremental renewable energy. If the total of owned and contract generation, plus incremental renewables, exceeds an LSEs energy requirement, the model reduces the dispatch of unassigned generation and assigns the differential between the renewable cost and the unassigned generation cost to the LSE in excess.

6. **Emerging Low Carbon Resources**: Specify any incremental low carbon resources to be developed by nameplate capacity.

7. **Emerging Low Carbon Ownership**: Specify the ownership shares of developed low carbon resources by LSE. For example, if Coal IGCC is developed by a single LSE, assign 100% in the cell that corresponds to that resource type and utility.

8. **Fuel Prices**: Specify the 2020 California generation burner tip natural gas price and 2020 delivered coal price in Wyoming in \$2008 dollars.

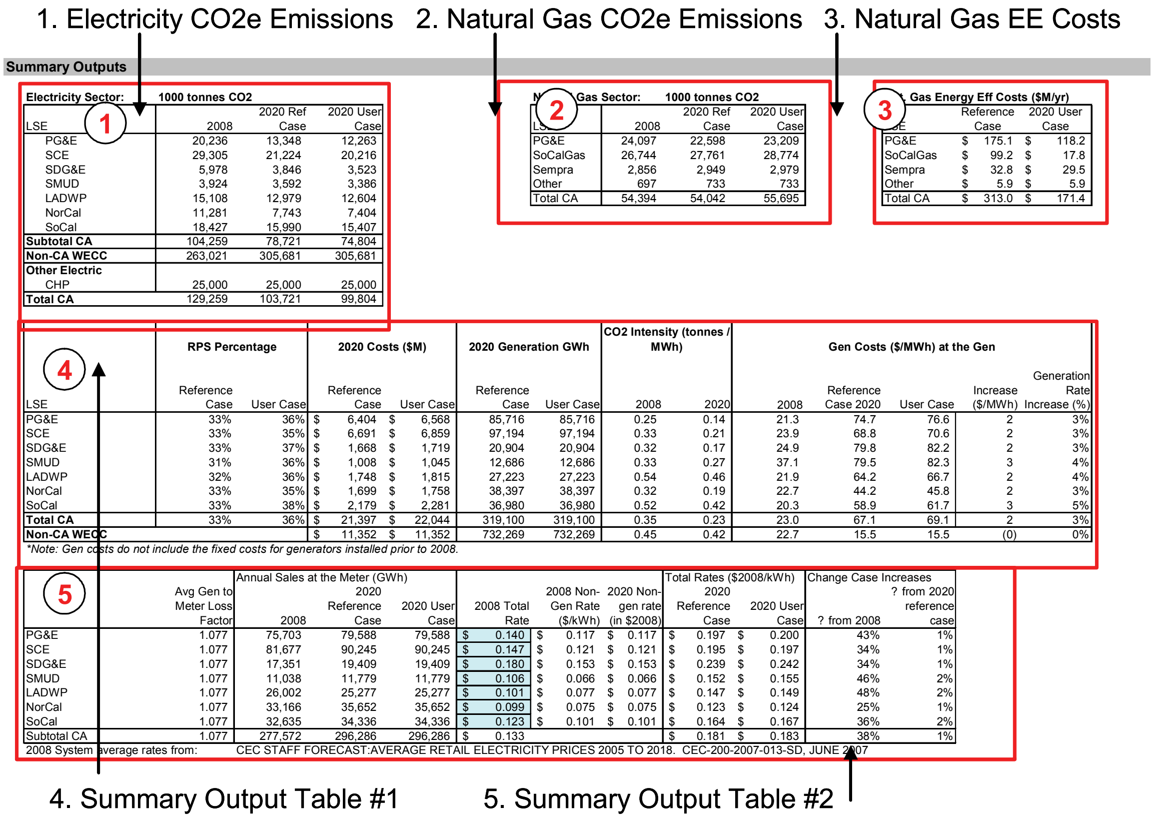
9. **Additions / Subtractions for Energy and Capacity Balance**: Review the results of the GHG Calculator energy and capacity balance. This is not an input, but a result. If the

total resources included in the reference case, plus the incremental renewables and low-carbon resources, are short of the necessary energy levels, the model will assume new natural gas CCGT installed and operated in California. The model will also remove new CCGT capacity if the energy is in excess of requirements. After the energy adjustment, if California is short of capacity, the model will install natural gas CT capacity for balancing.

Outputs

The outputs on the Main tab, as illustrated in Figure 12 below, provide high level results for the analyst to review as the Inputs in the 'user-defined' case are adjusted. Also, printing the Main tab will include the Title Bar, Inputs, and Summary Outputs to document a case.

Figure 12: Main Tab Outputs



Electricity Sector: 1000 tonnes CO2

LSE	2008	2020 Ref Case	2020 User Case
PG&E	20,236	13,348	12,263
SCE	29,305	21,224	20,216
SDG&E	5,978	3,846	3,523
SMUD	3,924	3,592	3,386
LADWP	15,108	12,979	12,604
NorCal	11,281	7,743	7,404
SoCal	18,427	15,990	15,407
Subtotal CA	104,259	78,721	74,804
Non-CA WECC	263,021	305,681	305,681
Other Electric			
CHP	25,000	25,000	25,000
Total CA	129,259	103,721	99,804

Gas Sector: 1000 tonnes CO2

LSE	2008	2020 Ref Case	2020 User Case
PG&E	24,097	22,598	23,209
SoCalGas	26,744	27,761	28,774
Sempra	2,856	2,949	2,979
Other	697	733	733
Total CA	54,394	54,042	55,695

Gas Energy Eff Costs ($M/yr)

LSE	Reference Case	2020 User Case
PG&E	$ 175.1	$ 118.2
SoCalGas	$ 99.2	$ 17.8
Sempra	$ 32.8	$ 29.5
Other	$ 5.9	$ 5.9
Total CA	$ 313.0	$ 171.4

LSE	RPS Percentage Reference Case	RPS Percentage User Case	2020 Costs ($M) Reference Case	2020 Costs ($M) User Case	2020 Generation GWh Reference Case	2020 Generation GWh User Case	CO2 Intensity (tonnes / MWh) 2008	CO2 Intensity (tonnes / MWh) 2020	Gen Costs ($/MWh) at the Gen 2008	Reference Case 2020	User Case	Increase ($/MWh)	Generation Rate Increase (%)
PG&E	33%	36%	$ 6,404	$ 6,568	85,716	85,716	0.25	0.14	21.3	74.7	76.6	2	3%
SCE	33%	35%	$ 6,691	$ 6,859	97,194	97,194	0.33	0.21	23.9	68.8	70.6	2	3%
SDG&E	33%	37%	$ 1,668	$ 1,719	20,904	20,904	0.32	0.17	24.9	79.8	82.2	2	3%
SMUD	31%	36%	$ 1,008	$ 1,045	12,686	12,686	0.33	0.27	37.1	79.5	82.3	3	4%
LADWP	32%	36%	$ 1,748	$ 1,815	27,223	27,223	0.54	0.46	21.9	64.2	66.7	2	4%
NorCal	33%	35%	$ 1,699	$ 1,758	38,397	38,397	0.32	0.19	22.7	44.2	45.8	2	3%
SoCal	33%	38%	$ 2,179	$ 2,281	36,980	36,980	0.52	0.42	20.3	58.9	61.7	3	5%
Total CA	33%	36%	$ 21,397	$ 22,044	319,100	319,100	0.35	0.23	23.0	67.1	69.1	2	3%
Non-CA WECC			$ 11,352	$ 11,352	732,269	732,269	0.45	0.42	22.7	15.5	15.5	(0)	0%

*Note: Gen costs do not include the fixed costs for generators installed prior to 2008.

LSE	Avg Gen to Meter Loss Factor	Annual Sales at the Meter (GWh) 2008	2020 Reference Case	2020 User Case	2008 Total Rate	2008 Non-Gen Rate ($/kWh)	2020 Non-gen rate (in $2008)	Total Rates ($2008/kWh) 2020 Reference Case	2020 User Case	Change Case Increases ? from 2008	? from 2020 reference case
PG&E	1.077	75,703	79,588	79,588	$ 0.140	$ 0.117	$ 0.117	$ 0.197	$ 0.200	43%	1%
SCE	1.077	81,677	90,245	90,245	$ 0.147	$ 0.121	$ 0.121	$ 0.195	$ 0.197	34%	1%
SDG&E	1.077	17,351	19,409	19,409	$ 0.180	$ 0.153	$ 0.153	$ 0.239	$ 0.242	34%	1%
SMUD	1.077	11,038	11,779	11,779	$ 0.106	$ 0.066	$ 0.066	$ 0.152	$ 0.155	46%	2%
LADWP	1.077	26,002	25,277	25,277	$ 0.101	$ 0.077	$ 0.077	$ 0.147	$ 0.149	48%	2%
NorCal	1.077	33,166	35,652	35,652	$ 0.099	$ 0.075	$ 0.075	$ 0.123	$ 0.124	25%	1%
SoCal	1.077	32,635	34,336	34,336	$ 0.123	$ 0.101	$ 0.101	$ 0.164	$ 0.167	36%	2%
Subtotal CA	1.077	277,572	296,286	296,286	$ 0.133			$ 0.181	$ 0.183	38%	1%

2008 System average rates from: CEC STAFF FORECAST:AVERAGE RETAIL ELECTRICITY PRICES 2005 TO 2018. CEC-200-2007-013-SD, JUNE 2007

1. **Electricity CO2e Emissions**: Provides the CO2e emissions associated with each LSE and for the entire state. Emissions from CHP are also included to compare with the appropriate electric sector benchmark.
2. **Natural Gas CO2e Emissions**: Provides the CO2e emissions associated with direct natural gas consumption in the residential, commercial, and industrial (less cogen) sectors by LSE and for the entire state.
3. **Natural Gas EE Costs**: Provides the costs of the natural gas energy efficiency programs by LSE.
4. **Summary Output Table #1**: Provides summary output related to generation mix and costs by LSE. Outputs provided include; RPS percentage, 2020 Total Utility Costs ($M), 2020 Generation (GWh), emission intensity (tonnes / MWh), generation costs ($/MWh) and cost differences between the reference case and the user defined case.
5. **Summary Output Table #2**: Provides summary output related to rate levels and rate impacts by LSE. Outputs include sales in 2008, 2020 reference case and 2020 user-defined case by LSE, retail rate levels in 2008 case, and estimates of retail rates in the 2020 reference case and 'user defined' case. All rates are expressed in $2008 real dollars.

41. GHG Calculator Spreadsheet
(Available on E3 Website: http://www.ethree.com/cpuc_ghg_model.html)

(END OF ATTACHMENT B)